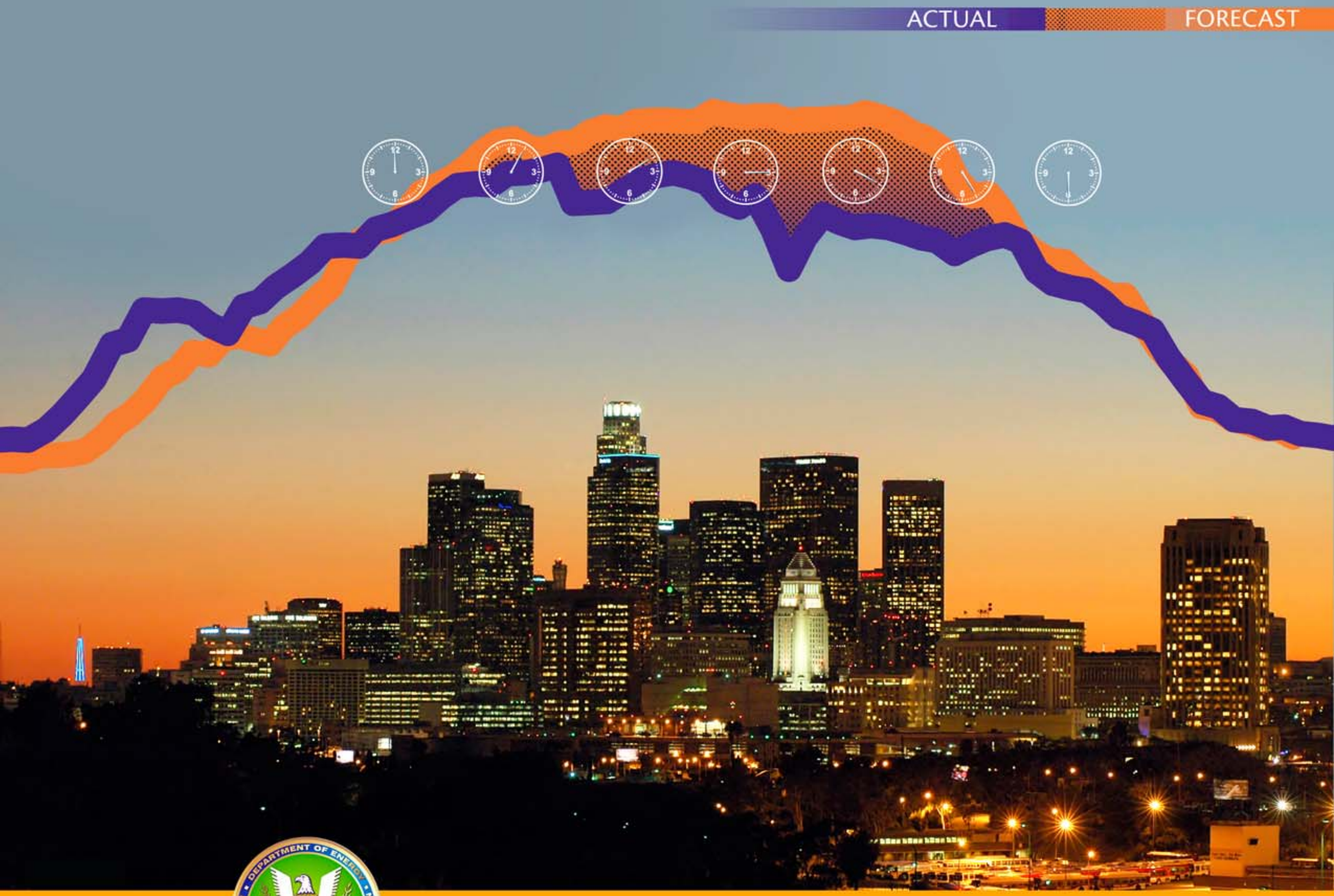
A National Assessment of
Demand Response Potential



Staff Report

Federal Energy Regulatory Commission

June 2009

Prepared by

The Brattle Group | Freeman, Sullivan & Co. | Global Energy Partners, LLC

A National Assessment of Demand Response Potential

Federal Energy Regulatory Commission
STAFF REPORT

Prepared by

The Brattle Group
Freeman, Sullivan & Co
Global Energy Partners, LLC

June 2009

ACKNOWLEDGEMENTS

The analysis presented in this report was produced by a team of consultants from The Brattle Group (TBG), Freeman, Sullivan & Co. (FSC) and Global Energy Partners (GEP). Each firm led different parts of the project, typically with significant input from the other firms. TBG managed the project and was the lead contractor to the Federal Energy Regulatory Commission (FERC). TBG also had the lead in producing this report. FSC was the lead contractor on model development, and also developed the state and customer-segment level load shapes that were used as starting points for developing demand response impacts. FSC and TBG worked together to develop price impacts that reflect the extensive research that has been done in this area. GEP had the lead on data development with input from both TBG and FSC. Gary Fauth, an independent consultant specializing in advanced metering business case analysis, had the lead role in producing the advanced metering deployment scenario that underlies one of the potential estimates. Senior staff from all three firms worked jointly to develop scenario definitions and to provide defensible input assumptions for key drivers of demand response potential.

We are grateful to Dean Wight, the FERC project manager, and Ray Palmer, David Kathan, Jessica L. Cockrell, George Godding, Jignasa Gadani and Judy L. Lathrop at FERC for their guidance through all stages of this project and for providing comments on earlier drafts of this report. We are also grateful to these experts who provided guidance and review: Charles Goldman, Anne George, Mark Lauby, Lawrence Oliva, Andrew Ott, and Lisa Wood.

The Brattle Group
Ahmad Faruqui
Ryan Hledik

Freeman, Sullivan & Co.
Stephen S. George
Josh Bode
Paul Mangasarian

Global Energy Partners, LLC
Ingrid Rohmund
Greg Wikler
Debyani Ghosh
Sharon Yoshida

TABLE OF CONTENTS

TABLE OF FIGURES

APPENDICES

LIST OF TABLES

Appendices

EXECUTIVE SUMMARY

Energy Independence and Security Act of 2007

Section 529 (a) of the Energy Independence and Security Act of 2007[1] (EISA 2007) requires the Federal Energy Regulatory Commission (Commission or FERC) to conduct a National Assessment of Demand Response Potential[2] (Assessment) and report to Congress on the following:

- Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;
- Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;
- Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and
- Recommendations for overcoming any barriers.

EISA 2007 also requires that the Commission take advantage of preexisting research and ongoing work and insure that there is no duplication of effort. The submission of this report fulfills the requirements of Section 529 (a) of EISA 2007.

This Assessment marks the first nationwide study of demand response potential using a state-by-state approach. The effort to produce the Assessment is also unique in that the Commission is making available to the public the inputs, assumptions, calculations, and output in one transparent spreadsheet model so that states and others can update or modify the data and assumptions to estimate demand response potential based on their own policy priorities. This Assessment also takes advantage of preexisting research and ongoing work to insure that there is no duplication of effort.

Estimate of Demand Response Potential

In order to estimate the nationwide demand response potential in 5 and 10 year horizons, the Assessment develops four scenarios of such potential to reflect different levels of demand response programs. These scenarios are: Business-as-Usual, Expanded Business-as-Usual, Achievable Participation and Full Participation. The results under the four scenarios illustrate how the demand response potential varies according to certain variables, such as the number of customers participating in existing and future demand response programs, the availability of dynamic pricing[3] and advanced metering infrastructure

[1] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act § 571, 42 U.S.C. §§ 8241, 8279) (EISA 2007). The full text of section 529 is attached as Appendix F.

[2] In the Commission staff's demand response reports, the Commission staff has consistently used the same definition of "demand response" as the U.S. Department of Energy (DOE) used in its February 2006 report to Congress:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report).

[3] In this Assessment, dynamic pricing refers to prices that are not known with certainty ahead of time. Examples are "real time pricing," in which prices in effect in each hour are not known ahead of time, and "critical peak pricing" in which prices on certain days are known ahead of time, but the days on which those prices will occur are not known until the day before or day of consumption. Static time-varying prices, such as traditional time-of-use rates, in which prices vary by rate period, day of the week and season but are known with certainty, are not part of this analysis.

(AMI)[4], the use of enabling technologies, and varying responses of different customer classes. Figure ES-1 illustrates the differences in peak load starting with no demand response programs and then comparing the four scenarios. The peak demand without any demand response is estimated to grow at an annual average growth rate of 1.7 percent, reaching 810 gigawatts (GW) in 2009 and approximately 950 GW by 2019.[5]

This peak demand can be reduced by varying levels of demand response under the four scenarios. Under the highest level of demand response, it is estimated that there would be a leveling of demand between 2009 and 2019, the last year of the analysis horizon. Thus, the 2019 peak load could be reduced by as much as 150 GW, compared to the Business-as-Usual scenario. To provide some perspective, a typical peaking power plant is about 75 megawatts[6], so this reduction would be equivalent to the output of about 2,000 such power plants.

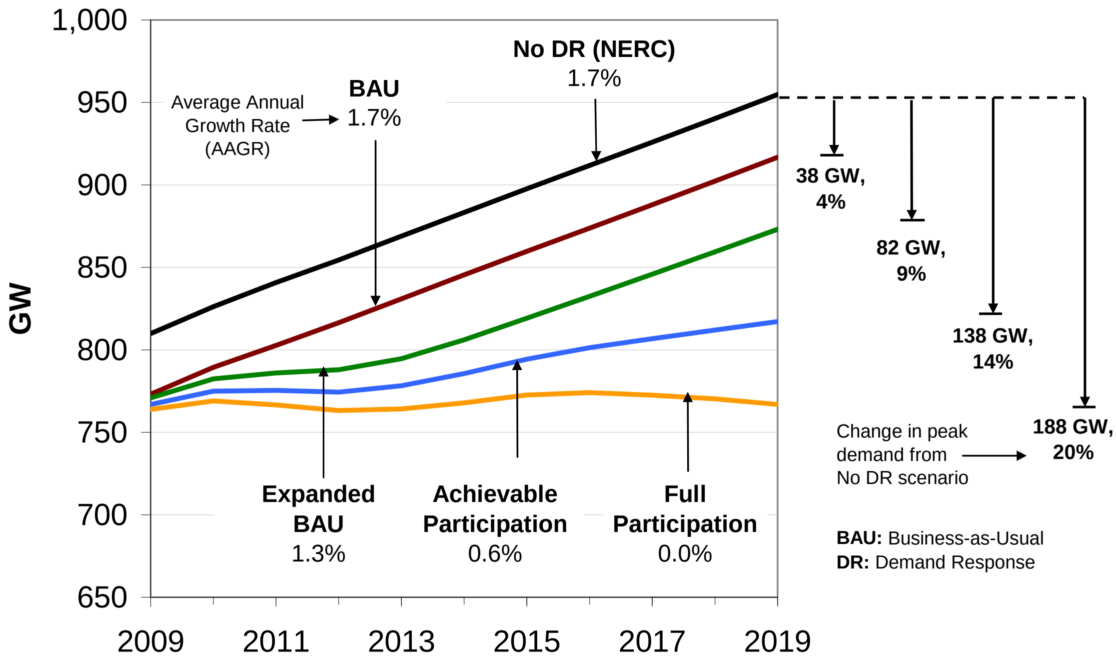


Figure ES-1: U.S. Peak Demand Forecast by Scenario

The amount of demand response potential that can be achieved increases as one moves from the Business-as-Usual scenario to the Full Participation scenario.

It is important to note that the results of the four scenarios are in fact estimates of **potential,** rather than **projections of what is likely to occur**. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the

[4] A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capacity to provide price information to customers that allows them to respond to dynamic or changing prices.

[5] The "No DR (NERC)" baseline is derived from North American Electric Reliability Corporation data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls

[6] Energy Information Administration, Existing Electric Generating Units in the United States, 2007, available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response.

As with any model-based analysis in economics, the estimates in this Assessment are subject to a number of uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[7]

Business-as-Usual Scenario

The Business-as-Usual scenario, which we use as the base case, considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over the next ten years. Such programs include interruptible rates and curtailable loads for Medium and Large commercial and industrial customers, as well as direct load control of large electrical appliances and equipment, such as central air conditioning, of Residential and Small commercial and industrial consumers.

The reduction in peak demand under this scenario is 38 GW by 2019, representing a four percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Expanded Business-as-Usual Scenario

The Expanded Business-as-Usual scenario is the Business-as-Usual scenario with the following additions: 1) the current mix of demand response programs is expanded to all states, with higher levels of participation ("best practices" participation levels);[8] 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers (5 percent) choosing dynamic pricing.

The reduction in peak demand under this scenario is 82 GW by 2019, representing a 9 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Achievable Participation Scenario

The Achievable Participation scenario is an estimate of how much demand response would take place if 1) advanced metering infrastructure were universally deployed; 2) a dynamic pricing tariff were the default; and 3) other demand response programs, such as direct load control, were available to those who decide to opt out of dynamic pricing. This scenario assumes full-scale deployment of advanced metering

[7] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

[8] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

infrastructure by 2019. It also assumes that 60 to 75 percent of customers stay on dynamic pricing rates, and that many of the remaining choose other demand response programs. In addition, it assumes that, in states where enabling technologies (such as programmable communicating thermostats) are cost-effective and offered to customers who are on dynamic pricing rates, 60 percent of the customers will use these technologies.

The reduction in peak demand under this scenario is 138 GW by 2019, representing a 14 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Full Participation Scenario

The Full Participation scenario is an estimate of how much cost-effective demand response would take place if advanced metering infrastructure were universally deployed and if dynamic pricing were made the default tariff and offered with proven enabling technologies. It assumes that all customers remain on the dynamic pricing tariff and use enabling technology where it is cost-effective.

The reduction in peak demand under this scenario is 188 GW by 2019, representing a 20 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Other Results of the Assessment

As shown in Figure ES-1, the size of the demand response potential increases from scenario to scenario, given the underlying assumptions.[9] Comparing the relative impacts of the four scenarios on a national basis, moving from the Business-as-Usual scenario to the Expanded Business-as-Usual scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing traditional programs in states that have little or no existing participation. However, more demand response can be achieved beyond these traditional programs. By also pursuing dynamic pricing the potential impact could further be increased by 54 percent, the difference between the Achievable Participation scenario and the Expanded Business-as-Usual scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an additional 33 percent increase in demand response potential (the difference between the Achievable Potential and Full Potential scenarios). A conclusion of this Assessment is that at the national level the largest gains in demand response impacts can be made

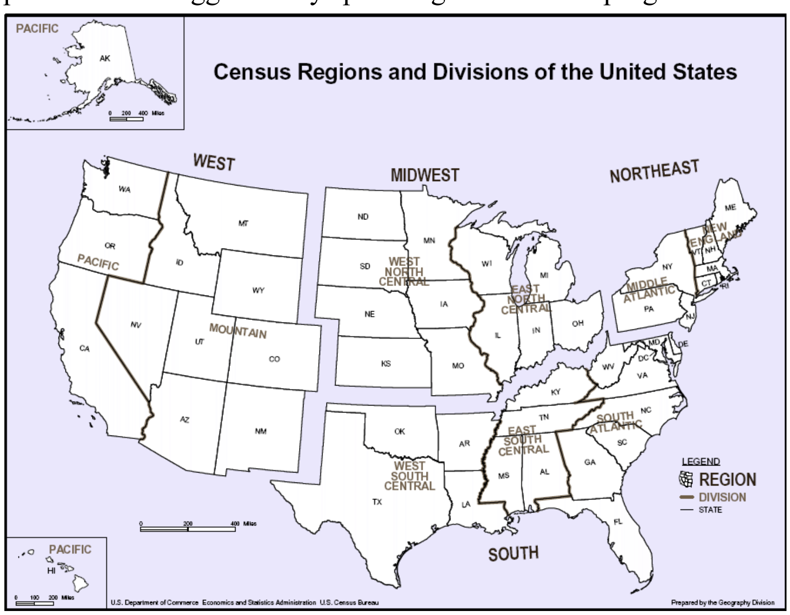


Figure ES- 2: Census Regions

[9] There are other technologies that have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

through dynamic pricing programs when they are offered as the default tariff, particularly when they are offered with enabling technologies.

A mapping of states divided into the nine Census Divisions is provided in Figure ES-2. Regional differences in the four demand response potentials are portrayed by Census Division in Figure ES-3. To adjust for the variation in size among the divisions, the impacts are shown as a percentage of each Division's peak demand.

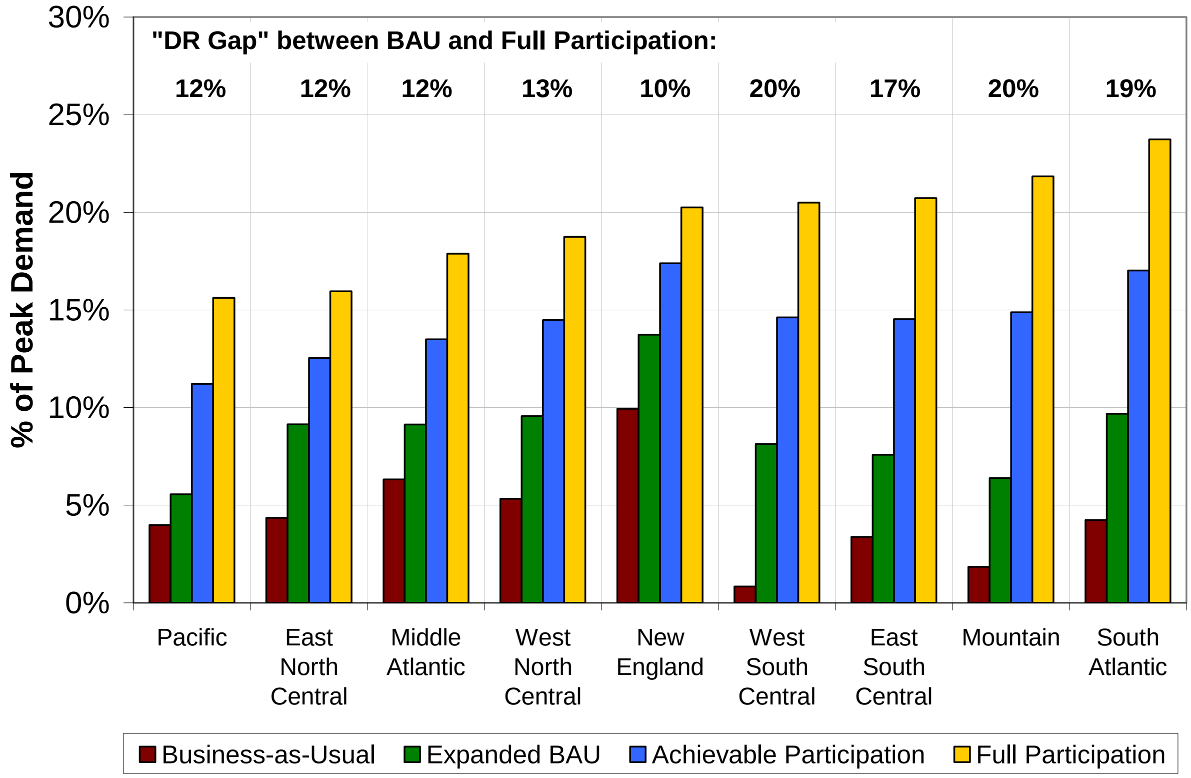


Figure ES-3: Demand Response Potential by Census Division (2019)

Regional differences in the estimated potential by scenario can be explained by factors such as the prevalence of central air conditioning, the mix of customer type, the cost-effectiveness of enabling technologies, and whether regions have both Independent System Operator/Regional Transmission Organization (ISO/RTO) and utility/load serving entity programs. For example, in the Business-as-Usual scenario, the largest impacts originate in regions with ISO/RTO programs that co-exist with utility/load serving entity programs. New England and the Middle Atlantic have the highest estimates, with New England having the ability to reduce nearly 10 percent of peak demand.

The prevalence of central air conditioning plays a key role in determining the magnitude of Achievable and Full Participation scenarios. Hotter regions with higher proportions of central air conditioning, such as the South Atlantic, Mountain, East South Central, and West South Central Divisions, could achieve greater demand response impacts per participating customer from direct load control and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Achievable and Full Participation scenarios, where dynamic pricing plays a more significant role, than in the Expanded Business-as-Usual scenario.

The cost-effectiveness of enabling technologies[10] also affects regional differences in demand response potential. Due to the low proportion of central air conditioning in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies, as determined in this study, do not outweigh the cost of the devices, so the effect of enabling technologies is excluded from the analysis. As a result, in some of these states and in some customer classes the demand reductions from dynamic pricing reflect only manual (rather than automated) customer response and so are lower than in states where customers would be equipped with enabling technologies. This also applies to the cost-effectiveness of direct load control programs.

The difference between the Business-as-Usual and Full Participation scenarios represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. Regions with the highest potential under the Full Participation scenario do not necessarily have the largest difference between Business-As-Usual and Full Participation. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having gaps of 12 percent or less. Other regions, particularly in the southeastern U.S., have differences of as much as 20 percent of peak demand.

Comparing the results for these four scenarios provides a basis for policy recommendations. For example, the difference between the Business-As-Usual scenario and the Full Participation scenario reveals the “gap” between what is being achieved today through demand response and what could economically be realized in the future if appropriate polices were implemented. Similarly, the difference between the Expanded Business-as-Usual and the Achievable Participation scenarios reveals the additional amount of demand response that could be achieved with policies that rely on both dynamic pricing and other types of programs. The Assessment also provides valuable insight regarding regional and state differences in the potential for demand response reduction, allowing comparisons across the various program types – dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify programs with the most participation today and those with the most room for growth.

Complete results for each of the fifty states and the District of Columbia are shown in Appendix A.

Barriers to Demand Response Programs and Recommendations for Overcoming the Barriers

A number of barriers need to be overcome in order to achieve the estimated potential of demand response in the United States by 2019. While the Assessment lists 25 barriers to demand response, the most significant are summarized here.

Regulatory Barriers. Some regulatory barriers stem from existing policies and practices that fail to facilitate the use of demand response as a resource. Regulatory barriers exist in both wholesale and retail markets.

- Lack of a direct connection between wholesale and retail prices.
- Measurement and verification challenges.
- Lack of real time information sharing.
- Ineffective demand response program design.

[10] The Assessment evaluates the cost-effectiveness of devices such as programmable communicating thermostats and excludes them where not cost-effective. See Chapter V for a complete description of the methodology.

- Disagreement on cost-effectiveness analysis of demand response.

Technological Barriers.

- Lack of advanced metering infrastructure.
- High cost of some enabling technologies.
- Lack of interoperability and open standards.

Other Barriers.

- Lack of customer awareness and education.
- Concern over environmental impacts.

As discussed above, three scenarios estimating potential reductions from the Business-as-Usual scenario have been developed. These scenarios estimate at 5 and 10 year horizons how much potential can be achieved by assuming certain actions on the part of customers, utilities and regulators. Each utility, together with state policy makers, must decide whether and how best to move forward with adoption of demand response, given their particular resources and needs; however, steps can be taken to help inform individual utility decisions and state policies, as well as national decisions.[11]

The increase in demand response under the Expanded Business-as-Usual scenario rests on the assumption that current "best practice"[12] demand response programs, such as direct load control and interruptible tariff programs, are expanded to all states and that there is some participation in dynamic pricing at the retail level. To encourage this expansion to all states and some adoption of dynamic pricing, FERC staff recommends that:

- Coordinated national and local education efforts should be undertaken to foster customer awareness and understanding of demand response, AMI and dynamic pricing.
- Information on program design, implementation and evaluation of these "best practices" programs should be widely shared with other utilities and state and local regulators.
- Demand response programs at the wholesale and retail level should be coordinated so that wholesale and retail market prices are consistent, possibly through the NARUC-FERC Collaborative Dialogue on Demand Response process.
- Both energy efficiency and demand response principles should be included and coordinated in education programs and action plans, to broaden consumers' and decision makers' understanding, improve results and use program resources effectively.
- Expanded demand response programs should be implemented nationwide, where cost-effective.
- Technical business practice standards for evaluating, measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets should be developed.

[11] On a separate track FERC issued the Wholesale Competition Final Rule, which recognized the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations. As part of the Final Rule, FERC required all RTOs and ISOs to study whether further reforms were necessary to eliminate barriers to comparable treatment of demand response in organized markets, among other things. Most RTOs and ISOs submitted filings that identified the particular barriers and possible reforms for their specific markets. Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008).

[12] See definition of "best practices" at note 7.

- Open standards for communications and data exchange between meters, demand response technologies and appliances should be encouraged and supported, particularly the efforts of the National Institute of Standards and Technology to develop interoperability standards for smart grid devices and systems.
- Cost-effectiveness tools should be developed or revised to account for many of the new environmental challenges facing states and the nation, and to reflect the existence of wholesale energy and capacity markets in many regions.
- Regulators and legislators should clearly articulate the expected role of demand response to allow utilities and others to 1) plan for and include demand response in operational and long-term planning, and 2) recover associated costs.

The Achievable Participation and Full Participation scenarios estimate that the largest demand response would take place if advanced metering infrastructure were universally deployed and consumers respond to dynamic pricing. The Achievable Participation scenario is realized if all customers have dynamic pricing tariffs as their default tariff and 60 to 75 percent of customers adopt this default tariff, while the Full Participation scenario is based on all consumers responding to dynamic prices. For this to occur, in addition to the recommendations above,

- Dynamic pricing tariffs should be implemented nationwide.
- Information on AMI technology and its costs and operational, market and consumer benefits should be widely shared with utilities and state and local regulators.
- Grants, tax credits and other funding for research into the cost and interoperability issues surrounding advanced metering infrastructure and enabling technologies should be considered, as appropriate.
- Expanded and comprehensive efforts to educate consumers about the advantages of AMI and dynamic pricing should be undertaken.

The Full Participation scenario is dependent upon removal of limitations to market acceptance through implementation of these recommendations, and all customers must be able to respond under dynamic pricing.

FERC is required by Section 529 of EISA 2007, within one year of completing this Assessment, to complete a National Action Plan on Demand Response. The Action Plan will be guided in part by the results of this Assessment.

CHAPTER I. PURPOSE OF THE REPORT

Introduction

This report fulfills the requirements of the Energy Independence and Security Act of 2007 (EISA 2007) to conduct a national assessment of demand response ("the Assessment") using a state-by-state approach. As required by the EISA 2007, the analysis examines the potential for demand response over a ten year forecast horizon, with 2010 being the first year of the forecast and 2019 being the final year. In addition, the report identifies the barriers to achieving demand response potential, as required in EISA 2007. The work has been informed by preexisting research on the topic. The analysis concludes with policy recommendations by Federal Energy Regulatory Commission (FERC) staff for ways to overcome the barriers to demand response. FERC has commissioned The Brattle Group, along with Freeman, Sullivan & Co. and Global Energy Partners LLC to conduct this analysis.

As used in this report, the term demand response is defined as follows: [13]

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

The Assessment quantifies demand response potential for four scenarios, each designed to answer a different question:[14]

- Business-as-Usual Scenario ("BAU"): What will demand response and peak demand be in five and ten years?
- Expanded BAU Scenario ("EBAU"): What will demand response and peak demand be in five and ten years if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, and there are modest amounts of pricing programs and advanced metering infrastructure (AMI)[15] deployment?
- Achievable Participation Scenario ("AP"): What is the potential for demand response and peak demand in five and ten years if AMI is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide to opt out of dynamic pricing?
- Full Participation Scenario ("FP"): What is the total potential amount of cost-effective demand response that could be achieved in five and ten years?

Comparing and contrasting the results for these four scenarios can answer a number of important questions. For example, the difference between the BAU scenario and the FP scenario reveals the "gap" between what is being achieved today through demand response and what could economically be realized in the future if the barriers are removed. Similarly, the difference between the EBAU and AP scenarios reveals the additional amount of demand response that could be achieved if policies shifted to an approach that relies on both economic and reliability based programs.

[13] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February, 2006.

[14] For more detail on the assumptions behind these scenarios, see Chapter V.

[15] A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capability to provide customers with price information, allowing them to respond to dynamic or changing prices.

The study also provides insight regarding regional differences in demand response potential. The state-level nature of the analysis allows for comparisons across different regions of the U.S. to identify areas where there is opportunity for substantial growth and adoption of demand response. Comparisons can also be made across various program types - dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify those programs with the most participation today and those with the most room for growth.

It is important to note that the results of the four scenarios are in fact estimates of **potential,** rather than **projections of what is likely to occur**. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response.

As with any model-based analysis in economics, the estimates in this Assessment are subject to a number of uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[16]

The bottom-up, state-specific nature of the Assessment has led to a number of key developments which will contribute to future research on the topic. Of primary importance is the development of a flexible, user-friendly model for assessing demand response potential. The model is an Excel spreadsheet tool that contains user friendly drop-down menus which allow users to easily change between demand response potential scenarios, import default data for each state, and change input values on either a temporary basis for use in "what if" exercises or on a permanent basis if better data are available.

Highlights of additional unique contributions are as follows:

- The Assessment is the first nationwide, bottom-up study of demand response potential using a state-by-state approach. Previous national studies have taken a top-down approach and as a result have not captured the varying regional effects of some of the key drivers of demand response potential, such as market penetration of central air conditioning. Other studies have utilized a bottom-up approach, but have been limited to specific geographical regions and do not allow for a consistent comparison across all parts of the U.S.
- The Assessment led to the development of an internally consistent, state-by-state database containing all inputs needed to do a bottom-up estimate of demand response potential.
- Normalized load shapes were developed for five sectors (Residential with central air conditioning, Residential without central air conditioning, Small commercial and industrial, Medium commercial and industrial, and Large commercial and industrial). Historical usage data from twenty-one states and a newly-developed load shape estimation model created load shapes for the other twenty-nine states.

[16] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

- Price elasticities and impacts estimates from 15 dynamic pricing pilots were synthesized to produce impacts estimates for each state. The impacts take into account differences in central air conditioning (CAC) saturation for residential customers, climate, and the effect of enabling technology.
- The Assessment led to the development of a comprehensive and thorough summary of barriers to the achievement of demand response at the retail and wholesale level.

Structure of the Report

Chapter II of the Assessment identifies the key assumptions for each of the four demand response scenarios, along with a brief justification for the definitions of the scenarios.

Chapter III provides a summary of the results, identifying important trends and insights at the national, regional, and state levels.

Chapter IV is a qualitative discussion of future trends and opportunities for reducing peak demand, particularly in light of recent developments in smart grid technology. Ideas for future research are also recommended.

Chapter V provides more detail on how the results were developed. It includes a description of the modeling methodology as well as a summary of the data development process. More detailed backup is provided in Appendix D.

Chapter VI identifies existing barriers to demand response. These are barriers that are currently contributing to the "gap" between the amount of demand response in place today and the potential estimates that are described in this report.

Chapter VII concludes the report by presenting policy recommendations for addressing the demand response barriers and moving closer to achieving the identified potential.

Contained in the appendices of this report are documents which support the findings and recommendations of this Assessment.

Appendix A provides detailed information on the demand response potential projections for each state.

Appendix B offers lessons learned in the development of the data used in this Assessment.

Appendix C provides detail on the analysis of barriers to achieving demand response potential.

Appendix D contains documentation of the database development process used to create the model inputs for the report.

Appendix E is an uncertainty analysis, which represents the magnitude and impact of the uncertainty related to the results of this Assessment.

Appendix F is the full text of the Energy Independence and Security Act of 2007, Section 529 which applies to this Assessment.

Finally, Appendix G contains a glossary of terms.

CHAPTER II. KEY ASSUMPTIONS

This chapter identifies the key assumptions that are important for interpreting and understanding the results of the Assessment. This includes the type of demand response programs that were included in the Assessment, definition of the customer classes considered, and the key distinctions between the four demand response scenarios. The purpose of this chapter is to provide context for the discussion of the key results in Chapter III. For details on specific assumptions and their justification, as well as on modeling methodology and data development, see Chapter V.

Customer Classes

Retail customers are divided into four segments based on common metering and tariff thresholds. Much of the data used in this Assessment was segmented in this way.

- Residential: includes all residential customers.
- Small commercial and industrial: commercial and industrial customers with summer peak demand[17] less than 20 kilowatts (kW).
- Medium commercial and industrial: commercial and industrial customers with summer peak demand between 20 and 200 kW.
- Large commercial and industrial: commercial and industrial customers with summer peak demand greater than 200 kW.[18]

Demand Response Program Types

The analysis includes five types of demand response programs: dynamic pricing without enabling technology, dynamic pricing with enabling technology, direct load control, interruptible tariffs, and "other" demand response programs such as capacity/demand bidding and wholesale programs administered by Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). These demand response program categories are defined below.

<u>Dynamic pricing without enabling technology</u>: Dynamic pricing refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. Prices are higher during peak periods to reflect the higher-than-average cost of providing electricity during those times, and lower during off peak periods, when it is cheaper to provide the electricity. The rates are dynamic in the sense that prices change in response to events such as high-priced hours, unexpectedly hot days, or reliability conditions.[19] Customers respond to the higher peak prices by manually curtailing various end-uses. For example, residential customers might turn up the set-point on their central air conditioner or reschedule their kitchen and laundry activities to avoid running their appliances during high priced hours. The higher

[17] Summer peak demand is the customer's highest instantaneous level of consumption during the summer season.

[18] There is some justification for further dividing this class to separately analyze very large C&I customers (i.e. with peak demand greater than 1 MW), as these customers would behave differently and potentially be eligible for different demand response programs. However, this group of customers is heterogeneous in size, end-uses, and consumption patterns. To separately analyze them is very challenging from a data perspective and is an area where further research could lead to additional valuable insights.

[19] This definition excludes time-of-use (TOU) rates. TOU rates, in which prices typically vary by rate period, day of week and season, have higher prices during all peak rate periods and lower prices during all off-peak rate periods. They have not been included in the portfolio of demand response options because they are static rates and do not provide a dynamic price signal to customers that can be used to respond to unexpectedly high-priced days or reliability events. Other forms of dynamic pricing include critical peak pricing, in which the prices on certain days are known ahead of time, but the days on which those prices occur are not known until the day before or day of, and real time pricing, in which prices in effect in each hour are not known ahead of time.

priced peak hours are accompanied by lower priced off-peak hours, providing customers with the opportunity to reduce their electricity bills through these actions.

Examples of dynamic rates include critical peak pricing, peak time rebates, and real-time pricing. Peak time rebate is different than critical peak pricing and real-time pricing rates in that rather than charging a higher price during critical events, customers are provided a rebate for reductions in consumption. The analysis assumes that advanced metering infrastructure (AMI) must be in place to offer any of these rates. AMI includes "smart meters" that have the capability to measure customer usage over short intervals of time (often 15 minutes), as opposed to many conventional meters that are read manually on a monthly basis.

Dynamic pricing with enabling technology: This program is similar to the previously described dynamic pricing program, but customers are also equipped with devices that automatically reduce consumption during high priced hours. For Residential and Small and Medium commercial and industrial customers, the automated technology (known as a programmable communicating thermostat) adjusts air conditioning energy use where such devices are determined to be cost-effective. Large commercial and industrial customers are assumed to be equipped with automated demand response[20] systems, which coordinate reductions at multiple end-uses within the facility.

Direct load control (DLC): Customer end uses are directly controlled by the utility and are shut down or moved to a lower consumption level during events such as an operating reserve shortage. For residential customers, an air-conditioning DLC program is modeled.[21] Direct control of other residential end uses, such as water heating, was not included.[22] Non-residential DLC programs include air-conditional load control as well, but could also include other forms of DLC in some states, such as irrigation control.

Interruptible tariffs: Customers agree to reduce consumption to a pre-specified level, or by a pre-specified amount, during system reliability problems in return for an incentive payment of some form. The programs are generally only available for Medium and Large commercial and industrial customers.

Other DR programs: The Other DR category includes programs primarily available to Medium and Large commercial and industrial customers such as capacity bidding, demand bidding, and other aggregator offerings, whether operated by an ISO, RTO, or a utility in an area without an ISO or RTO. This category also includes demand response being bid into capacity markets. Some of these programs are primarily price-triggered while others are triggered based on reliability conditions.

We have excluded certain options from the scope of our study that are sometimes included in the definition of demand response. These include static time-of-use (TOU) rates, back up generation, permanent load shifting and plug-in hybrid vehicles (PHEVs). The reasons are briefly described below.

Often, demand response studies will include the impacts of all rates that are "time varying." Time varying rates typically are structured such that customers are offered higher prices during peak periods when demand for electricity is at its highest. This higher peak price is accompanied by a discounted, lower price during the remaining hours. By providing customers with rates that more accurately reflect the true cost of providing electricity over the course of the day, customers have an incentive to shift load from the peak period to the off-peak period, thus reducing the overall cost of providing electricity.[23]

Within the family of time-varying rates, there is a distinction between rates that are "static" and those that are "dynamic." For dynamic rates, as described previously, the peak period price can be triggered to

[20] Automated demand response is a communications infrastructure that provides the owner of the system with electronic signals that communicate with the facility's energy management control system to coordinate load reductions at multiple end-uses.

[21] Such DLC programs could be based on a programmable communicating thermostat or a conventional "switch" that cycles the air conditioner. For the purposes of this analysis, a switch is the basis for the DLC program.

[22] These other forms of DLC were excluded because they represent a fairly small share of aggregate DLC program impacts and the state-level appliance saturation data necessary to conduct such an analysis was not readily available.

[23] Alternatively, a rebate could be offered for consumption curtailment during peak periods.

target specific system events, such as high-priced hours, unexpectedly hot days, or reliability conditions. Customers are typically notified of the higher peak period price on a day-ahead or day-of basis. Static rates, on the other hand, do not have this feature and instead use fixed peak and off-peak prices that do not change regardless of system conditions. TOU rates fall under this category of static time-varying rates. While TOU rates provide incentive to permanently shift load from peak periods to off-peak periods, they do not have the flexibility to allow for an increase in response on short notice.

In addition, in many parts of the country TOU rates have been in place for decades and as a result their impacts are already factored into the reference load forecast. Further, FERC's Demand Response Survey database[24] impact estimates are not available for many TOU rates. It is for these reasons that TOU rates were excluded from the analysis.

Programs that specifically target back-up generation were excluded as well. However, if back-up generation as a technology underlies demand response for a more general program, that program was included. Additionally, permanent load shifting was excluded because it cannot be dispatched dynamically to meet system requirements. It is analogous to energy efficiency, which is also excluded from the scope of this report. Finally, we have excluded PHEVs because there is insufficient data to analyze their impacts and because, given the current absence of significant market penetration of PHEVs, their impact over the 10 year analysis horizon will likely be small.

Demand Response Scenarios

Four scenarios have been considered in this analysis. The first, Business-as-Usual, is simply a measure of existing demand response resources and planned growth in these resources. The other three scenarios are measurements of demand response potential under varying assumptions. All three of the demand response potential scenarios are limited only to cost-effective demand response programs, meaning that the net present value of the benefits of a given program exceeds the costs.[25]

Business-as-Usual (BAU) is an estimate of demand response if current and planned demand response stays constant. This scenario is intended to reflect the continuation of current programs and tariffs. In most instances, growth in program impacts is not modeled, although where information is available that explicitly states likely growth projections, that information has been included. The value in this scenario is that it serves as the starting point against which to benchmark the three other demand response potential scenarios.

Expanded BAU (EBAU) is an estimate of demand response if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, along with a modest amount of demand response from pricing programs and AMI deployment.[26] The key assumption driving participation in the non-pricing programs is that all programs achieve participation rates that are representative of "best practices." This scenario provides insight regarding what could be achieved through more aggressive pursuit of programs that exist today. However, it does not account for those programs that are not heavily pursued today but have significant potential, such as residential dynamic pricing.

Achievable Participation (AP) is an estimate of demand response if AMI is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide not to enroll in

[24] Available at http://www.ferc.gov/industries/electric/indus-act/demand-response/2008/survey.asp

[25] For the purposes of this Assessment, the Total Resource Cost (TRC) test is used. More information on the cost-effectiveness screening is provided in Chapter V.

[26] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

dynamic pricing. Customer participation rates were developed to reflect the reality that not all customers will participate in demand response programs. In this scenario, participation in dynamic pricing programs is not limited as it is in the EBAU scenario, and all demand response programs can be equally pursued. This scenario considers the potential inherent in all available demand response programs while restricting the total potential estimate to maximum participation levels that could likely be achieved in reality.

Full Participation (FP) is an estimate of the total amount of cost-effective demand response. This scenario assumes that there are no regulatory or market barriers and that all customers will participate. The value of this scenario is that it quantifies the upper-bound on demand response under the assumptions and conditions modeled in this Assessment.[27]

Comparing the Key Scenario Assumptions

The four scenarios are differentiated by a set of distinguishing assumptions. The differentiation is driven mostly by assumptions about pricing programs. Table 1 summarizes these key differences.

Table 1: Key Differences in Scenario Assumptions

Assumption	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
AMI deployment	Partial Deployment	Partial deployment	Full deployment	Full deployment
Dynamic pricing participation (of eligible)	Today's level	Voluntary (opt-in); 5%	Default (opt-out); 60% to 75%	Universal (mandatory); 100%
Eligible customers offered enabling tech	None	None	95%	100%
Eligible customers accepting enabling tech	None	None	60%	100%
Basis for non-pricing participation rate	Today's level	"Best practices" estimate	"Best practices" estimate	"Best practices" estimate

In the Full Participation and Achievable Participation scenarios, AMI is assumed to reach 100 percent deployment in all states by 2019. In the EBAU scenario, only partial deployment of AMI is achieved, depending on the current status of utility deployment plans in each state. This is consistent with the definition of the EBAU scenario as focusing heavily on non-pricing demand response programs, which do not require AMI for operation. By 2019, in the EBAU scenario, AMI market penetration ranges from 20 percent to 100 percent with a national average of about 40 percent. The BAU scenario assumes the existence only of those AMI systems that are in place today or for which plans for deployment have been announced.

Dynamic pricing is assumed to be widely available in the AP and FP scenarios. In the FP scenario, it is the only rate that is offered to customers. In the AP scenario, dynamic pricing is offered on a default basis, meaning that all customers are enrolled in a dynamic rate but they can "opt out" to a different rate type. Forty percent of Medium and Large commercial and industrial customers are assumed to opt out of the dynamic rate, as are 25 percent of Residential and Small commercial and industrial customers.[28] The EBAU scenario assumes a minimal amount of participation in dynamic pricing, with the rate being

[27] Technologies not modeled in the Assessement also have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

[28] For details on the basis for these assumptions, see Chapter V.

offered on a voluntary (opt-in) basis and only five percent of the customers in each customer class choosing to enroll.[29]

Another significant driver of the difference between the three demand response potential scenarios is the share of customers equipped with enabling technologies. Customers with enabling technology are a subset of those enrolled in dynamic pricing. In addition to being enrolled in dynamic pricing, for a customer to be equipped with enabling technology in a given scenario it must meet three criteria. It must first have load that is suitable for the technology,[30] then it must be offered the technology, and finally it must accept the technology.

In the FP scenario, all eligible customers with load suitable for the technology are assumed to be offered the technology where it is cost-effective. Further, all of the customers who are offered the technology are assumed to accept it. In the AP scenario, acceptance rates for both the utility and the customer reflect the reality that the equipment will not be utilized in all instances where it makes economic sense to do so. In this scenario, 95 percent of eligible customers are offered the technology and 60 percent of eligible customers who are offered the technology accept it. Enabling technologies are not part of the EBAU or BAU scenarios. These market acceptance rates are largely assumption-driven for the purposes of defining the scenarios. Given the illustrative nature of these assumptions, they are ideal candidates for an uncertainty analysis.

Participation rates in the non-dynamic pricing programs (DLC, interruptible tariffs, and Other DR) are determined using estimates of "best practices" developed using survey data from FERC's 2008 Assessment of Demand Response and Smart Metering. These participation rates are held constant on a percentage basis across ***all three scenarios*** and are applied to the segment of the population that is not participating in dynamic pricing. Thus, the major difference between the scenarios is that the participation rates are applied to a different population of eligible customers. More details on the development of the final participation rates are provided in Chapter V.

In most studies of demand response, data from multiple data sources must be brought together and reconciled to create a coherent and internally consistent picture. That is especially true of this study, where multiple scenarios of demand response potential have been created for the fifty states and the District of Columbia. In the construction of the BAU scenario, the Assessment has relied on a top-down approach that yields aggregate impacts of demand response potential. The main data source has been the FERC demand response survey. The construction of the other three scenarios has relied on a bottom-up approach that expresses demand response potential as the product of existing peak-demand, percent drop in load per participating customer and number of participating customers. In most cases, the assumptions underlying these other scenarios are consistent with the data underlying the BAU scenario.

However, in a few cases where the BAU numbers are a high proportion of the peak demand forecast, intrinsic discrepancies between the bottom-up and top-down approaches have prevented a complete reconciliation of the data from different sources. Empirically, the effect of these discrepancies is likely to be very small in magnitude and confined to small states with large amounts of existing demand response. In these states, the demand response potential may be slightly overstated, by not more than a percentage point or so. For the majority of states in the Assessment, the impact would be negligible and is dwarfed by other uncertainties in factors such as the peak load forecast, the per-customer impact of specific demand response programs and projections of the number of participating customers. In the future, this discrepancy could be reduced with more-detailed survey data to support the BAU scenario. FERC staff is evaluating changes to its survey methodology with this objective in mind. Also, the North American Electric Reliability Corporation (NERC) has designed and is refining a systematic approach to collecting demand response data that will contribute to the accuracy and usefulness of future analyses.[31]

[29] For programs in states where enrollment is already greater than five percent, the existing participation rate overrides this value.

[30] For example, for residential customers, only those with central air conditioning would be eligible for a programmable communicating thermostat since it specifically applies to air conditioning load. This assumption does not vary across scenarios but does vary across customer classes and states.

[31] See NERC, Demand Response Data Availability System (DADS) Preliminary Report, Phase I&II, June 3, 2009.

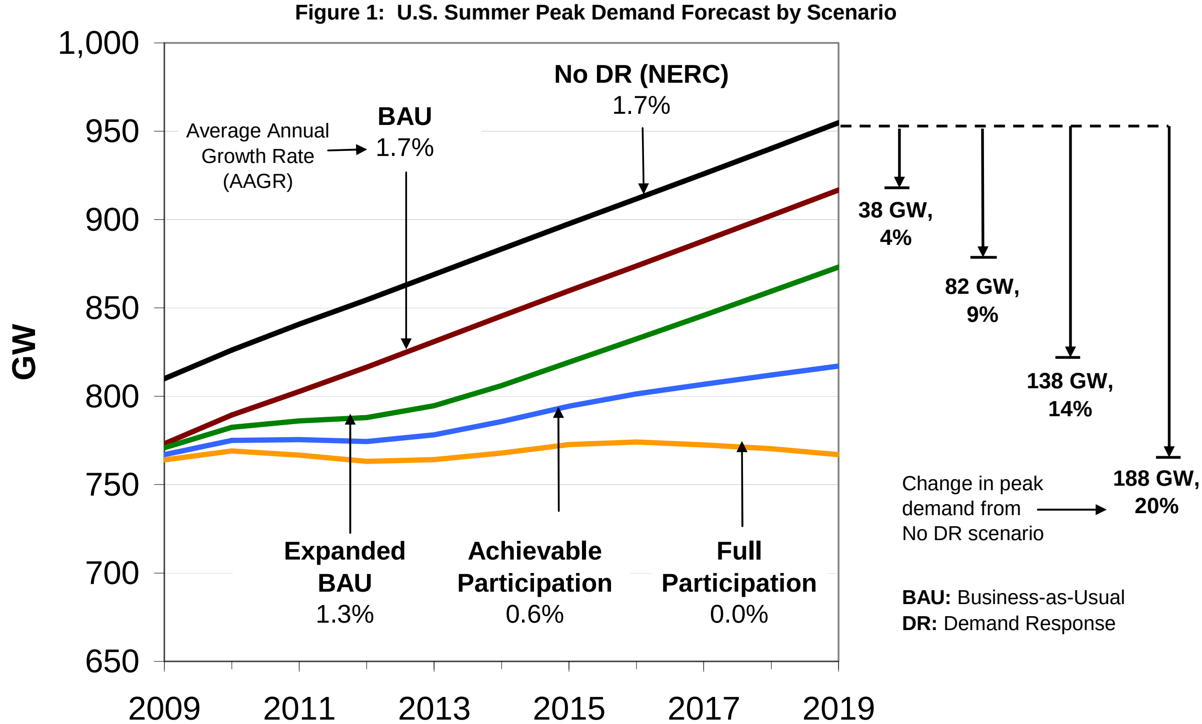
CHAPTER III. KEY RESULTS

This chapter summarizes the key results of the Assessment, identifies important trends in the findings, and compares demand response potential across scenarios, classes, program types, and regions. These findings are summarized for the U.S. as a whole, at the Census Division level, and at the state level.

National Results

A comparison of the demand response estimates under the four scenarios illustrates the potential impact of demand response on peak demand over the analysis horizon. This is illustrated in Figure 1. For the purposes of this Assessment, 2009 is considered to be the base year, and 2010 through 2019 is considered to be the analysis horizon.

Figure 1: U.S. Summer Peak Demand Forecast by Scenario



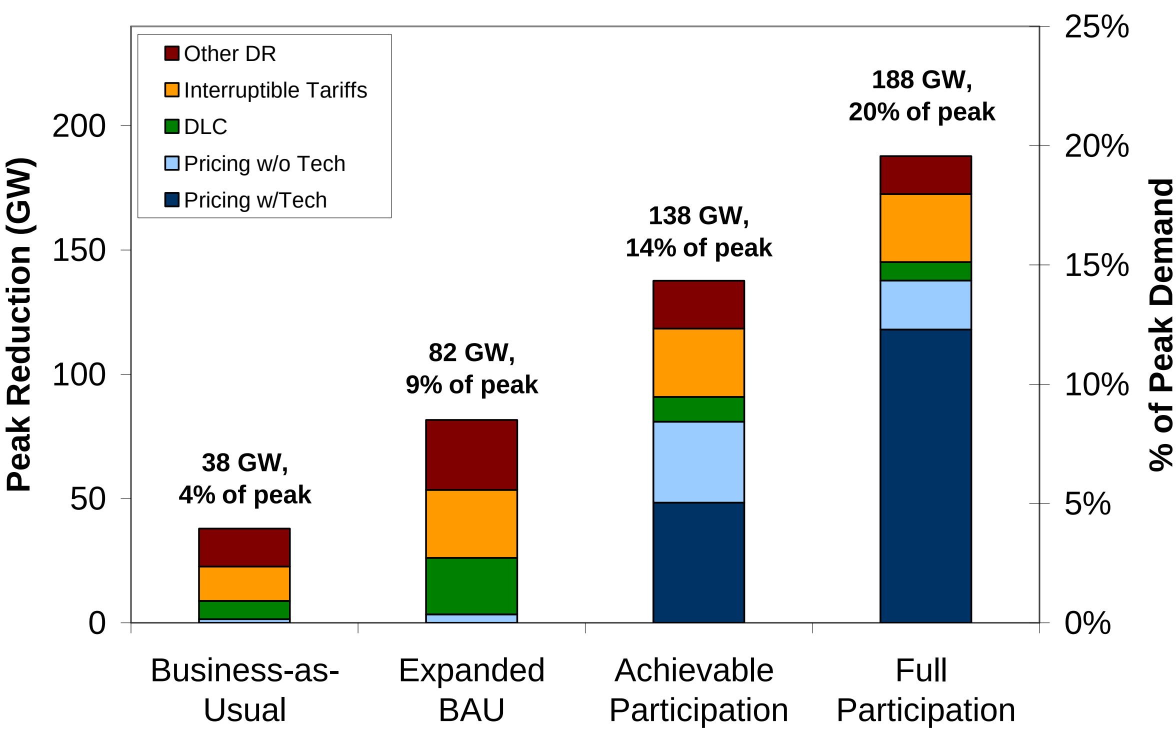
The black line represents a U.S. peak demand forecast that does not include any demand response, as provided by the North American Electric Reliability Corporation (NERC).[32] Peak demand begins at about 810 GW in 2009 and grows at an average annual growth rate (AAGR) of 1.7 percent, reaching slightly more than 950 GW by 2019. Peak demand in the BAU scenario grows at a very similar rate, but is lower overall. The reduction in peak demand under BAU, relative to the NERC forecast without demand response, is 37 GW in 2009 and 38 GW by 2019, representing a four percent reduction in peak demand. The EBAU demand response scenario produces a peak demand estimate that grows at an AAGR of 1.3 percent per year as a result of further reduction in peak demand of 82 GW, or nine percent, by 2019. The AP scenario produces even larger reductions in peak demand, reducing the AAGR to 0.6

[32] The "No DR (NERC)" baseline is derived from NERC data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls. http://www.nerc.com/page.php?cid=4|38|41

percent by reducing the peak by 138 GW, or 14 percent, by 2019. The FP scenario produces the largest reductions. Under this scenario, peak demand growth is approximately zero, and by 2019 would be 188 GW (20 percent) less than if there were no demand response programs in place.[33]

The peak demand reduction estimates under the three demand response potential scenarios show a dip between 2010 and 2013, after which the reductions increase at varying rates. This pattern is a result of the assumed market penetration schedule of new demand response programs. For the traditional programs (i.e. direct load control, interruptible and curtailable, and RTO-sponsored), states are assumed to ramp-up to final participation rates over the five year period between 2009 and 2014 in an "S-shaped curve." In other words, between 2009 and 2010, these programs experience relatively little incremental growth and the growth in peak demand is greater than the growth in demand response reductions. Then, between 2010 and 2013, the incremental increase in demand response is much higher, resulting in negative peak load growth during those years. After that, the incremental increase is smaller and the new programs mature and reach full participation (as a percentage of total customers) by 2015. Further, the effect of dynamic pricing over time is dependent on AMI market penetration, which increases throughout the forecast horizon. The more aggressive AMI deployment assumption in the AP and FP scenarios explains why demand response increases more significantly in the later years of those scenarios.

Figure 2: U.S Demand Response Potential by Program Type (2019)



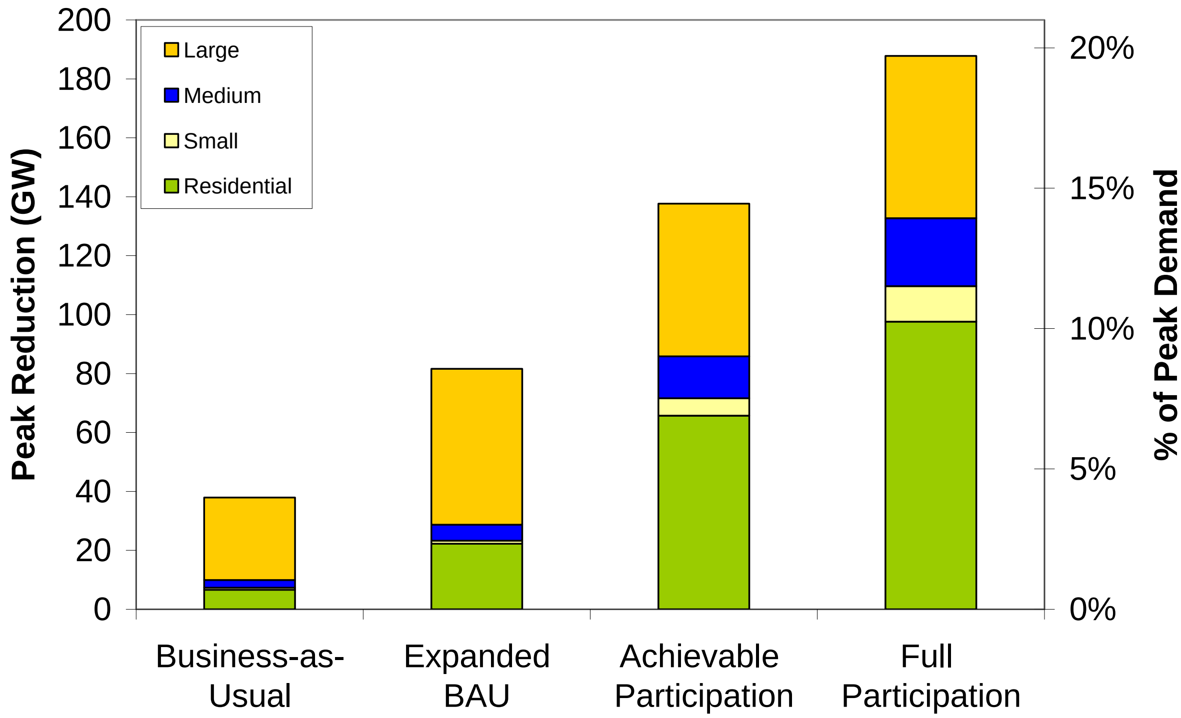
It is interesting to compare the relative impacts of the four scenarios. Moving from the BAU scenario to the EBAU scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing non-pricing programs in states that have little or no existing participation. However, more demand response can be achieved beyond these non-pricing programs. By also pursuing dynamic pricing the potential impact could further be increased by 68 percent, the difference between the AP scenario and the EBAU scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an

[33] This study assumes demand response occurs for four hours a day during the 15 highest load days of the year. Thus it reduces peak demand, but not necessarily demand in other (non-peak) times, and it may not reduce overall load growth in proportion to the reduction in peak demand.

additional 36 percent increase in demand response potential (the difference between the AP and FP Scenarios). A conclusion of this Assessment is that at the national level, the largest gains in demand response impacts can be made through pricing programs, particularly when offered with enabling technologies. This is more pronounced in the FP scenario, where roughly 70 percent of the impacts come from pricing programs. These findings are presented in Figure 2.

Just as demand response programs contribute to total demand response potential in varying degrees, so do the customer segments. Today, the majority of demand response comes from Large commercial and industrial customers, primarily through interruptible tariffs and capacity and demand bidding programs. However, it is the residential class that represents most untapped potential for demand response. As seen below, the impacts from this class drive the major differences in the demand response potential scenarios. Based on the assumptions underlying this study, residential customers provide the greatest per-customer impacts from pricing programs. While residential customers provide only roughly 17 percent of today's demand response potential, in the AP scenario they provide over 45 percent of the potential impacts. This is illustrated in Figure 3.

Figure 3: U.S. Demand Response Potential by Class (2019)



Regional Results

To identify regional differences in demand response potential, the results can be broken out at the level of the nine Census Divisions. A mapping of states to these regions is provided in Figure 4.

Regional differences in demand response potential are driven by many factors, including the customer mix, the market penetration of central air conditioning equipment, cost-effectiveness of new demand response programs, per-customer impacts from existing programs, participation in existing programs, and AMI deployment plans. A summary of the regional demand response potential estimates by scenario is provided in Figure 5.

Figure 4: The Nine Census Divisions

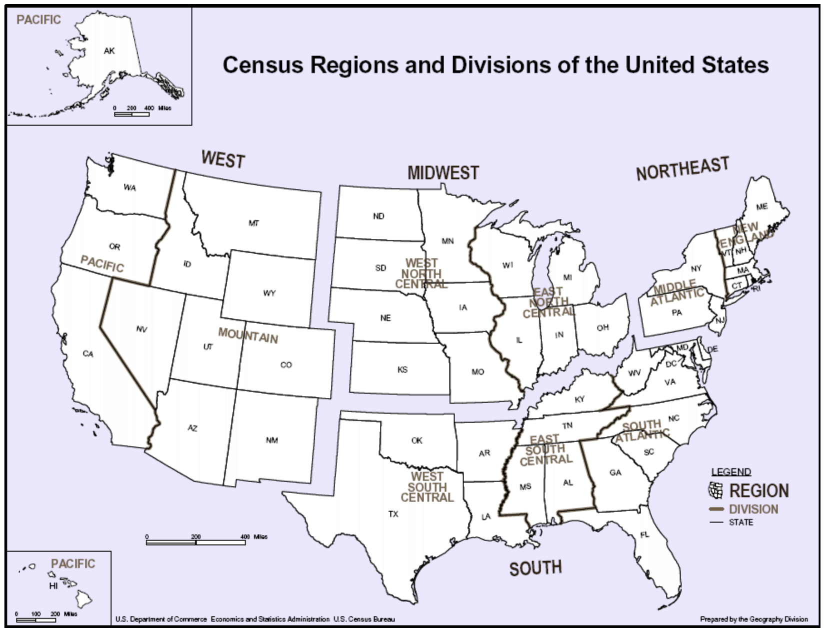
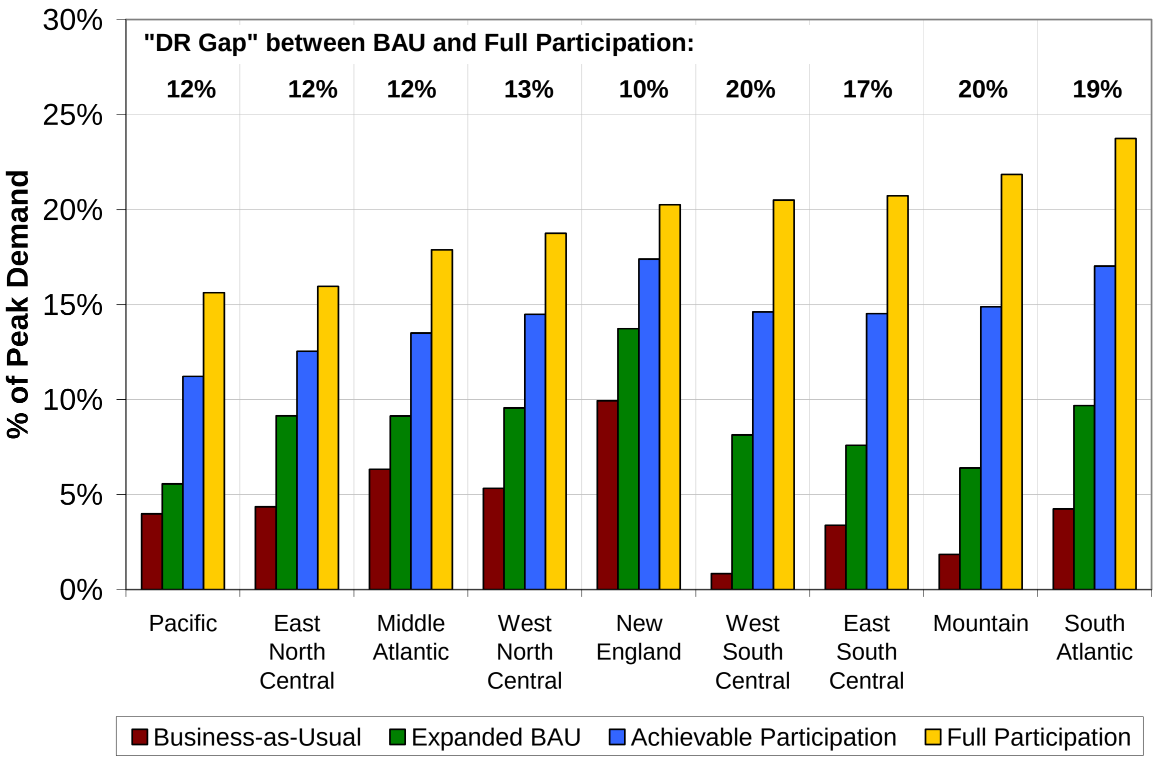


Figure 5: Demand Response Potential by Census Division (2019)



The largest existing (BAU) impacts are in regions with both wholesale demand response programs and utility/load serving entity programs. Thus, New England and the Middle Atlantic have the highest estimates for the BAU scenario, with New England reporting to have the ability to reduce nearly 10 percent of peak demand through demand response programs. Regions without significant wholesale organized markets demand response activity and relatively small existing programs, such as the West South Central and Mountain Divisions, have lower BAU estimates.

Central air conditioning saturation plays a key role in determining the magnitude of AP and FP demand response potential. Hotter regions with high central air conditioning saturations, such as the South Atlantic, Mountain, East South Central, and West South Central Divisions could achieve greater average per-customer impacts from DLC and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the AP and FP scenarios where dynamic pricing plays a more significant role than in the EBAU scenario.

Demand response potential in the EBAU scenario is driven partly by the customer mix in a given region. Specifically, regions with a higher share of load in the Large commercial and industrial sector will tend to have larger potential under this scenario. By definition, the EBAU scenario focuses on programs, such as interruptible tariffs and Other DR, that are geared toward these customers. Large commercial and industrial customers participating in these programs tend to produce large peak reductions, so regions with more load in the commercial and industrial class have higher potential. This potential will partly be determined by the average per-customer impacts that have been reported for these programs in each state. Those states reporting very high impacts will demonstrate the most potential.

The cost-effectiveness of enabling technologies also plays a role in driving regional differences in demand response potential. Due to lower per-customer air conditioning loads in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies do not outweigh the cost of the devices, and several states in these regions do not pass the cost-effectiveness screen.[34] As a result, in these states the impacts from dynamic pricing are only a function of manual customer response and are lower than in states where customers would be equipped with the technologies. This also applies to the cost-effectiveness of DLC programs, although these programs are found to be cost-effective for customer classes in most states.

It is interesting to quantify the "demand response gap" between the BAU scenario and the FP scenario. This gap represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. It is not necessarily the regions with the highest FP potential that have the largest demand response gap. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having demand response gaps less than or equal to 12 percent. Other regions are significantly farther from achieving the full potential for demand response, falling short of FP potential by as much as 20 percent of peak demand.

State-level Results

At the most granular level, demand response potential was estimated for each of the fifty states and the District of Columbia. Across the states, there is significant variation in both existing demand response impacts and in the potential for new demand response. This variation can be seen in a comparison of the distribution of impacts across the states for the four scenarios, as provided in Figure 6.

[34] For more information on the cost-effectiveness analysis, see Chapter V and Appendix D.

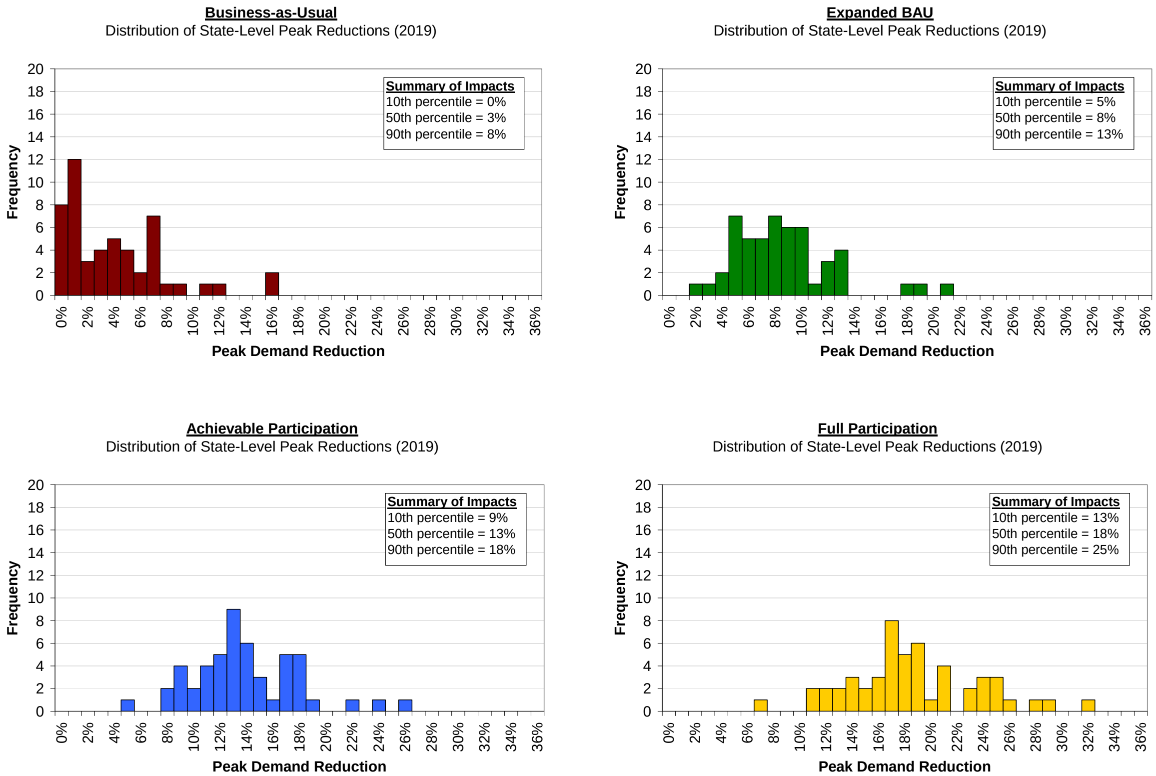


Figure 6: Comparison of Demand Response Impact Distribution across States

There is the least variation in impacts in the BAU scenario. In this scenario, demand response reductions are generally clustered between zero and five percent, with half of the state reductions being three percent or less. There are a few states that have reported the ability to achieve peak reductions greater than or equal to 10 percent today. These states are generally in the New England and Middle Atlantic regions and are reporting significant demand response enrollment by large commercial and industrial customers in wholesale demand response programs. The presence of strong wholesale programs plays a very significant role in the amount of existing demand response potential.

State-level impacts in the EBAU demand response scenario increase significantly relative to the BAU scenario. In Figure 6, this is shown by the rightward shift of the green bars along the horizontal axis relative to the red bars. In this scenario, the median demand response reduction is nine percent, while the range of the potential impacts is between two and 18 percent.

The AP impacts further shift to the right, with a median impact of 14 percent and a range of impacts from five percent up to 23 percent. The FP potential presents the widest distribution of potential impacts, ranging from seven percent to 31 percent and a median of 17 percent. This widening of the distribution across the scenarios is attributable to the increasingly important role of state-specific end-use characteristics such as central air conditioning saturation. To fully interpret the state-level impacts, it is necessary to consider some case studies in more detail. These are presented in the following section.

State Case Studies

To illustrate the details of the demand response potential estimations at the state level, it is helpful to walk through case studies of a few states that are distinctly different from each other yet generally representative of a larger group of states. Three such states have been selected: Georgia, Connecticut, and Washington. Georgia has existing demand response and some AMI in place and is not a member of an ISO/RTO while Connecticut has a significant amount of existing demand response, particularly in

ISO/RTO programs. Washington, on the other hand, has essentially no existing demand response. It is a region that historically has had a large amount of hydropower capacity and as a result has been energy constrained but not capacity constrained.[35] Washington also has low central air conditioning saturation, limiting the potential for future growth in demand response in this analysis.

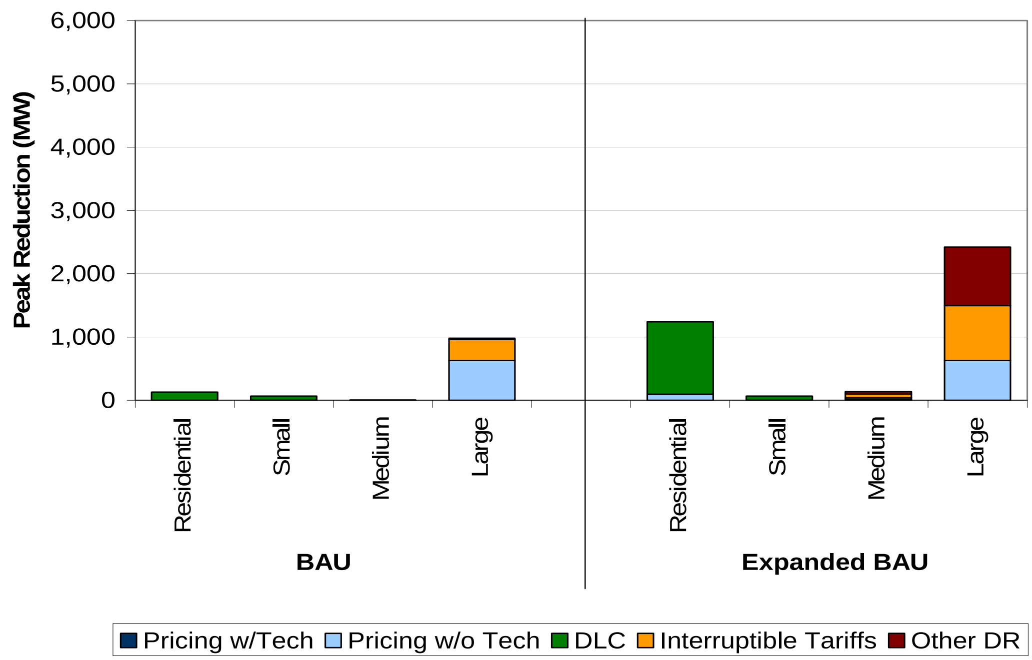
Case Study #1: Georgia

Today, Georgia's level of demand response is similar to the national average. The majority of peak impacts come from one of the nation's largest real-time pricing programs for Large commercial and industrial customers, as well as an interruptible tariff. Some additional impacts come from Residential and Small commercial and industrial DLC programs. In total Georgia is achieving a peak demand reduction of roughly 1.2 GW, or about 3.4 percent of the projected 2019 peak demand for Georgia of 34.7 GW.

In the EBAU scenario (Figure 7), participation in existing programs increases and new, primarily non-pricing programs are added. Significant growth takes place in the residential DLC program due to Georgia's high central air conditioning saturation rate of 82 percent. Medium and Large commercial and industrial customers are assumed to participate in a new capacity/demand bidding type of program (Other DR)[36] and a small amount of peak reduction could come from Small commercial and industrial DLC as well. Participation in these programs is assumed to achieve "best practices" levels that are the 75th percentile of participation rates in existing programs.

Pricing impacts remain significant in the existing Large commercial and industrial program, but under the EBAU scenario assumptions of a mild, voluntary rate offering, they do not play a significant role for the other customer classes. Relative to the BAU scenario, total impacts grow from 1.2 GW to 4.2 GW, or from 3.4 percent of peak demand to 12 percent.

Figure 7: Georgia BAU and EBAU Peak Demand Reduction in 2019



---

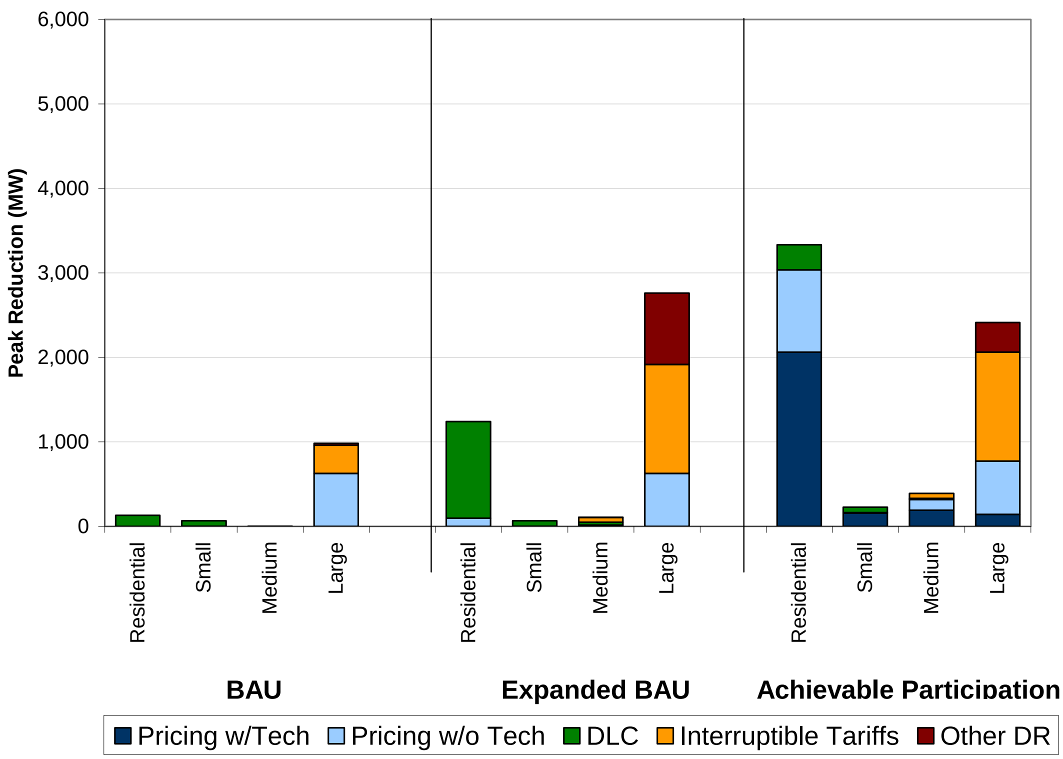
[35] In other words, hydropower resources can be ramped up to meet peak demands for a few hours but there are seasonal limits on energy production.

[36] Outside of RTO markets, capacity payments could be set at avoided capacity cost levels or could be negotiated on a case-by case basis with demand response providers.

Georgia's high residential central air conditioning saturation means that average per-customer impacts from dynamic pricing will be significant. As a result, in the AP scenario (Figure 8) impacts for the residential class increase under the assumption that dynamic pricing is offered as the default (opt-out) rate for all customers and 75 percent of the customers remain on the rate. A fraction of these customers (60 percent of those with central air conditioning) accept enabling technology – customers who, under the EBAU scenario and in the absence of the availability of enabling technology might have chosen to enroll in the DLC program. Additionally, of the customers who do not enroll in dynamic pricing, some are assumed to instead enroll in the DLC program. Based on a high-level assessment of the cost effectiveness of these programs, both were found to be economic for all customer classes in the state under the EBAU scenario.[37]

Interestingly, total impacts for the Large commercial and industrial class decrease in the AP scenario. The reason for this is that some customers who would have enrolled in Other DR programs under the EBAU scenario are instead assumed to have enrolled in dynamic pricing. The average per-customer peak reductions in Other DR programs (40 percent reduction) are higher than those of dynamic pricing (seven percent without enabling technology, 14 percent with enabling technology) and, as a result, the Large commercial and industrial potential drops in the AP scenario.[38] While this defining assumption of the AP scenario results in small impacts for the Large commercial and industrial class relative to the EBAU scenario, demand response potential for the entire state is higher. In total, the AP scenario potential system peak impacts increase to 6.4 GW, or 18 percent of peak demand.

Figure 8: Georgia BAU, EBAU, and AP Peak Demand Reduction in 2019



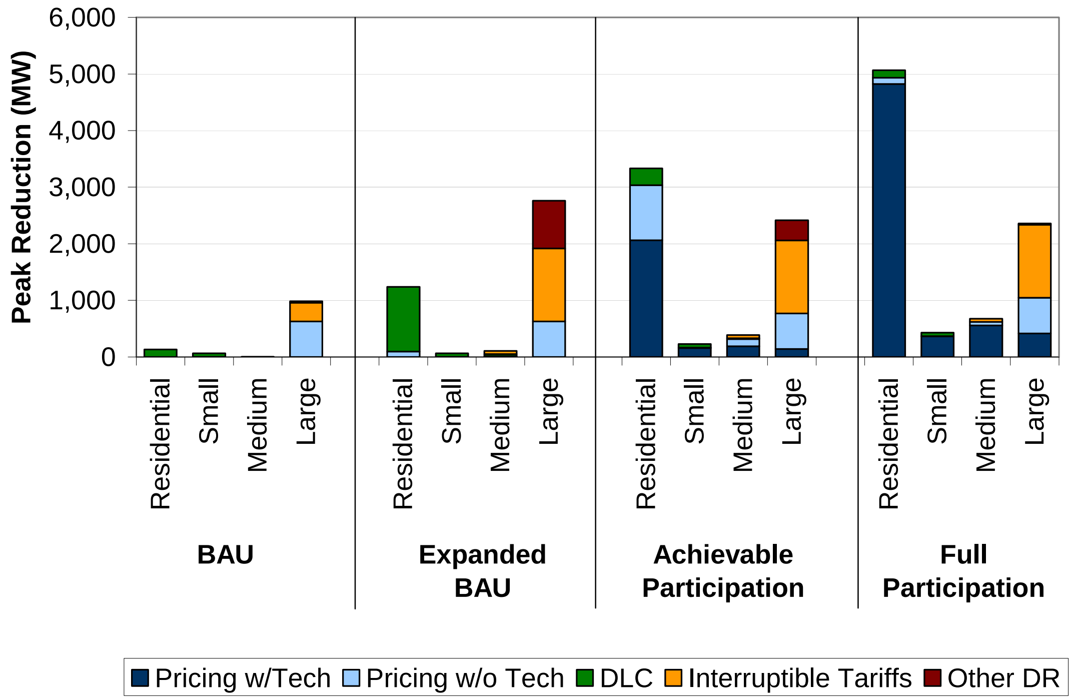
By definition, impacts are largest for the FP scenario (Figure 9). All customers are enrolled in dynamic pricing, with enabling technology being accepted by all customers. Customers currently enrolled in DLC are assumed to remain in that program. Total Large commercial and industrial impacts drop relative to

[37] Details on the cost effectiveness assessment are provided in Chapter V and Appendix D.

[38] It should be noted that the per-customer impacts from Other DR programs are based on the average of reported per-customer impacts in the 2008 FERC Demand Response survey. It is possible that impacts of this magnitude would not be achieved on a regular basis in practice and this is a topic that should be examined further.

the AP scenario, as the remaining participants in the Other DR programs are assumed to participate in dynamic pricing with enabling technology. However, on a system basis the total impacts increase to 8.5 GW, or 25 percent of peak demand in 2019. This is the total amount of cost-effective demand response potential in the state under the assumptions of this scenario. For more information on Georgia, see Appendix A.

Figure 9: Georgia Potential Peak Demand Reduction in All Scenarios, 2019

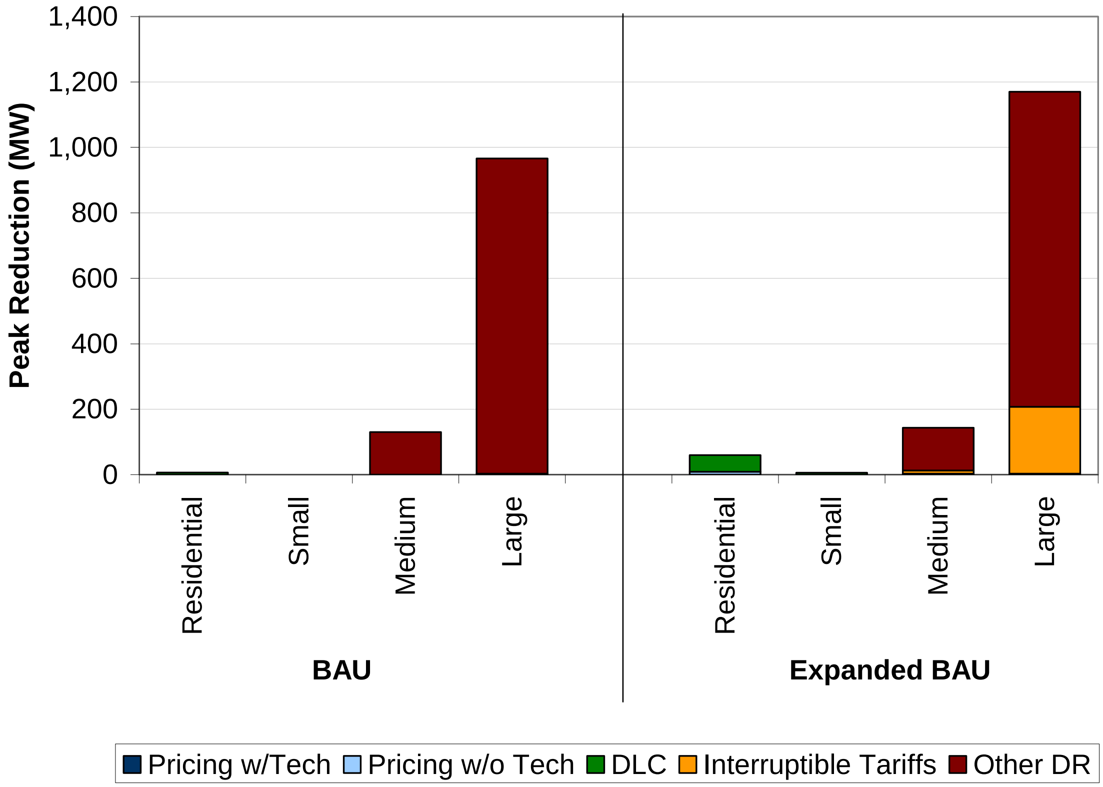


Case Study #2: Connecticut

Relative to Georgia, Connecticut is currently achieving significantly greater peak reductions from demand response on a percentage basis. In fact, Connecticut has one of the largest BAU demand response estimates of this Assessment. Where Georgia was achieving a 3.4 percent reduction, Connecticut is anticipating nearly a 13 percent reduction by 2019 in the BAU case. Much of this is due to large impacts being reported through participation in the ISO New England Forward Capacity Market. For the purposes of this Assessment, those impacts have been reported in the Other DR program category for Large commercial and industrial customers. Utility demand bidding programs in Connecticut are included in this category as well. The Other DR category represents nearly the entirety of the BAU peak reduction potential of 1,369 MW, or 16 percent of peak demand.

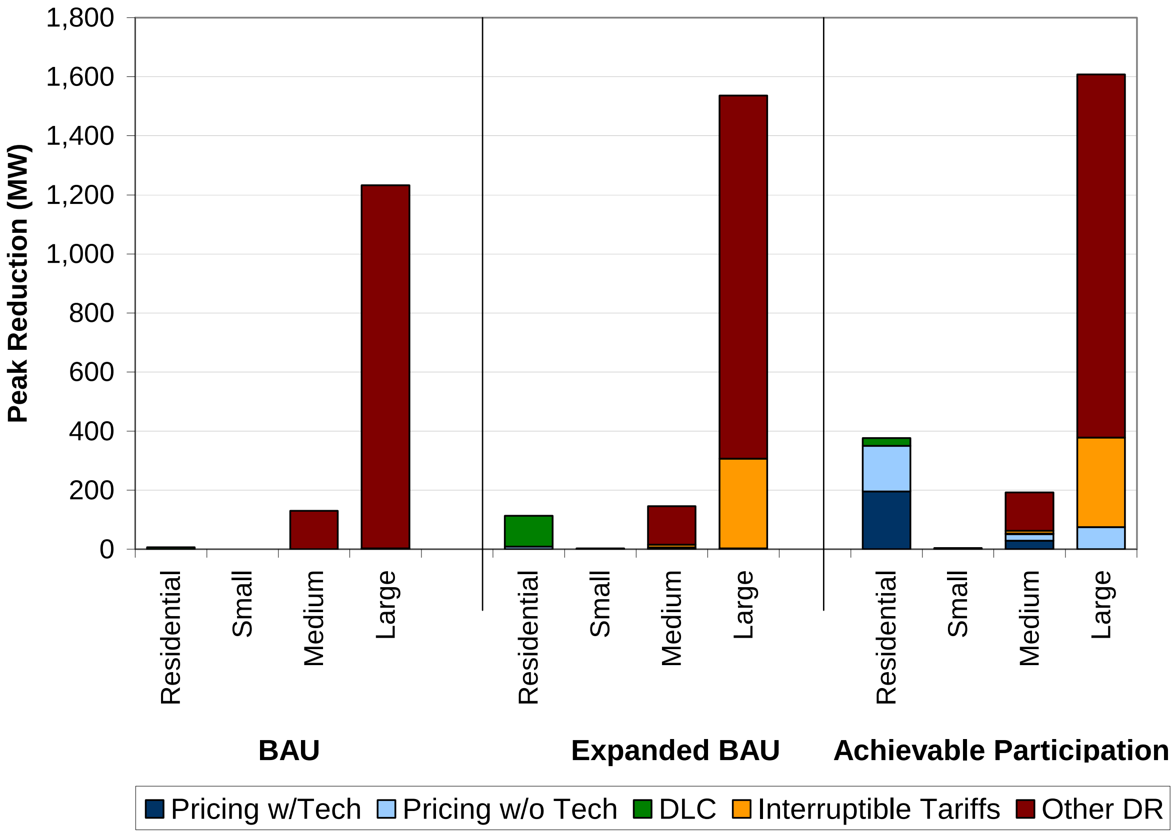
The EBAU scenario (Figure 10) assumes that programs will be put in place for other customer classes as well. DLC programs would increase demand response potential, although the low central air conditioning load in the residential class means that the impacts are not as significant as were seen in Georgia. Some additional Large commercial and industrial customers are assumed to participate in an interruptible tariff, but participation in Other DR does not increase as it is already beyond the 75th percentile of existing programs. (This study caps participation at the 75th percentile, unless participation in a program already exceeds that). Therefore, the total impact increases relative to the BAU scenario, but not to the degree that was seen in Georgia. Peak reduction potential increases from 1,369 MW to 1,798 MW or from 16 percent of peak demand to 21 percent.

Figure 10: Connecticut BAU and EBAU Peak Demand Reductions in 2019



Inclusion of default dynamic pricing in the AP scenario (Figure 11) increases overall demand response potential, but the incremental increase again is significantly smaller compared to Georgia. In the residential sector, this is driven by the low central air conditioning saturation rate. For Large commercial and industrial customers, existing participation in Other DR programs persists in the AP scenario impacts. The customers currently enrolled in Other DR programs are assumed to remain on those programs rather than enrolling in dynamic pricing. As a result, impacts from dynamic pricing are small but total impacts for the class remain large. The small potential impacts from dynamic pricing are further amplified by the fact that enabling technologies were not found to be cost-effective for Small and Large commercial and industrial customers in Connecticut, and therefore were assumed not to be available to customers in these classes. The end result is an increase in total demand response potential to 2181 MW, or 26 percent of peak demand in 2019.

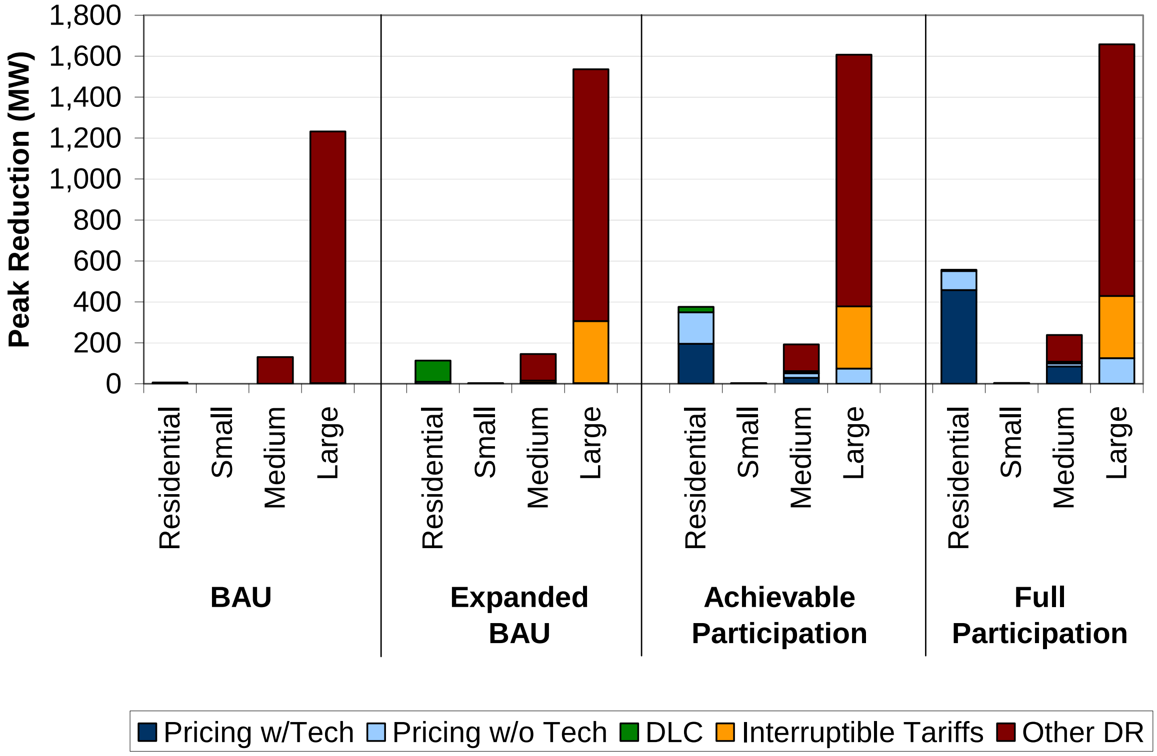
Figure 11: Connecticut BAU, EBAU, and AP Peak Reductions in 2019



Mandatory dynamic pricing further increases demand response potential in the FP scenario (Figure 12). This is coupled with a higher assumed acceptance rate for enabling technologies across the customer classes, and total demand response potential increases to 2,458 MW, or 29 percent of peak demand. The fairly small incremental increase relative to the AP scenario is partly attributable to enabling technologies not being cost effective for Small and Large commercial and industrial customers.

Relative to Georgia, the total potential for demand response is higher in Connecticut across the scenarios. While most categories of demand response programs actually have a lower potential in Connecticut, the presence of an ISO program that is reporting very large impacts makes for a higher overall potential estimate. It is also interesting to note that the incremental increase in demand response potential relative to the BAU scenario is smaller in Connecticut due to the large amount of existing demand response in the state. One interpretation of this finding is that Connecticut is currently achieving more of its potential. In other words, the "gap" between today's impacts and the total amount that could be achieved is smaller. A side-by-side comparison of all four scenarios is presented in Figure 12.

Figure 12: Connecticut Potential Peak Demand Reduction in All Scenarios, 2019



Case Study #3: Washington

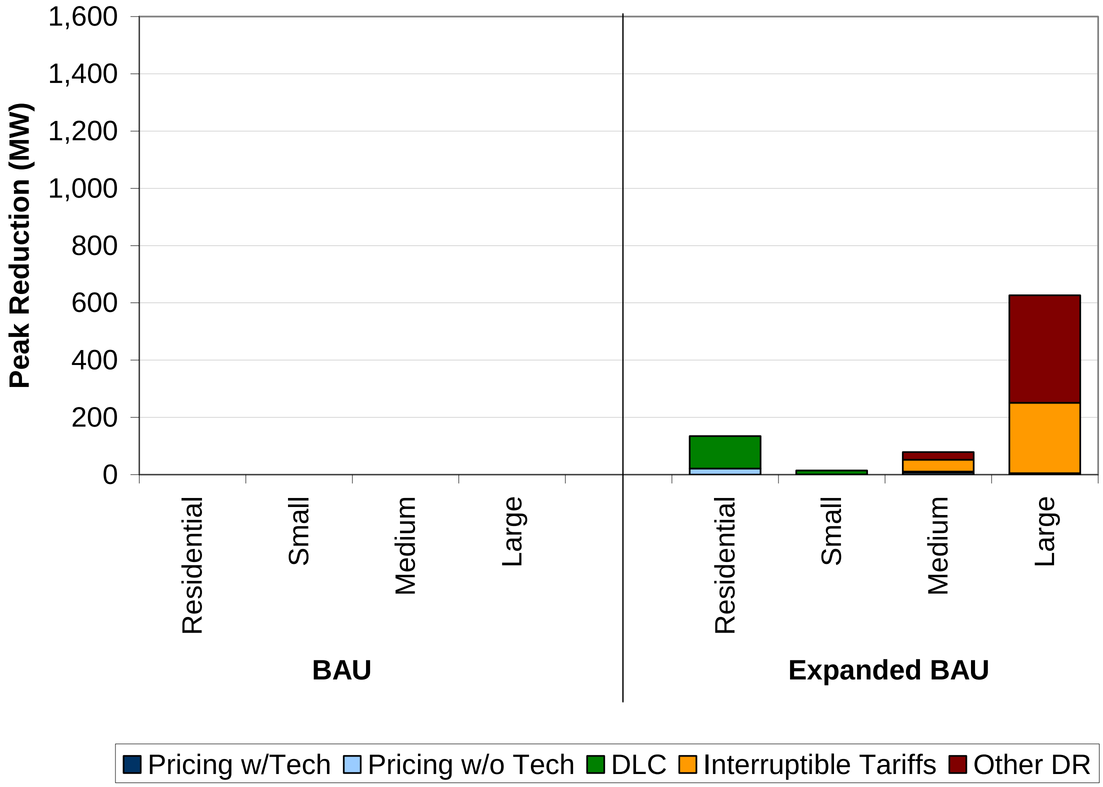
In contrast to both Georgia and Connecticut, no impacts from existing demand response programs were identified in the 2008 FERC survey for the state of Washington. This is generally a reflection of the state of demand response in the Pacific Northwest. Historically, low energy prices and a surplus of hydro capacity have made demand response seemingly less attractive in this region. However, as peak demand continues to grow and constraints on the operation of hydro facilities become more restrictive[39], utilities in the region are beginning to take a more serious look at demand response as a resource option.[40]

For Washington, the EBAU scenario (Figure 13) represents the addition of an entirely new portfolio of non-pricing demand response programs which are assumed to reach "best practices" levels for the U.S. Dynamic pricing is included on a voluntary opt-in basis. Impacts are spread somewhat evenly across DLC and interruptible tariffs, with the largest impacts coming from Other DR programs. Total demand response potential for the scenario is 864 MW, or four percent of peak demand.

[39] Environmental constraints related to wildlife preservation have become more stringent.

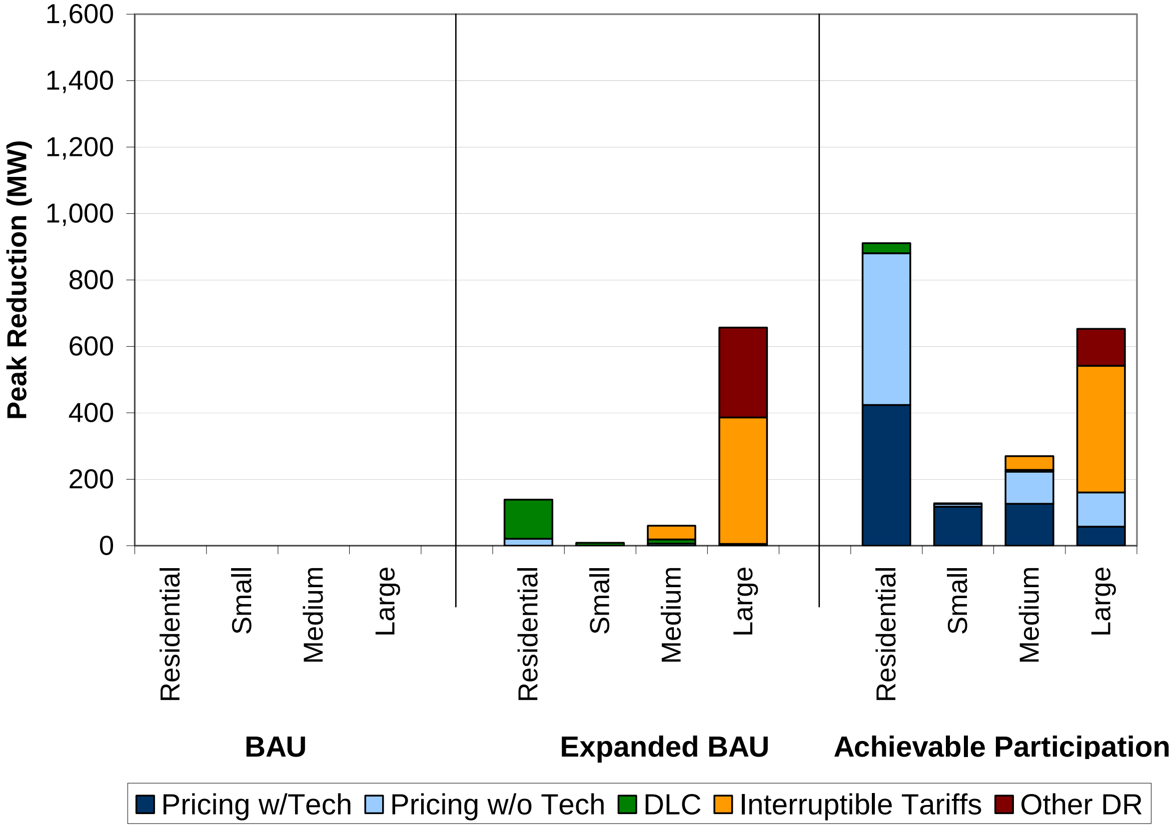
[40] For example, Bonneville Power Administration, the wholesale provider of electricity for the region, has recently begun to explore opportunities to partner with its retail electric utility customers to integrate demand response into its portfolio of resource options. Source: http://www.bpa.gov/Energy/N/utilities_Sharing_EE/Utility_Brown_Bag/pdf/120408DR_BrownBag.pdf

Figure 13: Washington BAU and EBAU Peak Demand Reduction in 2019



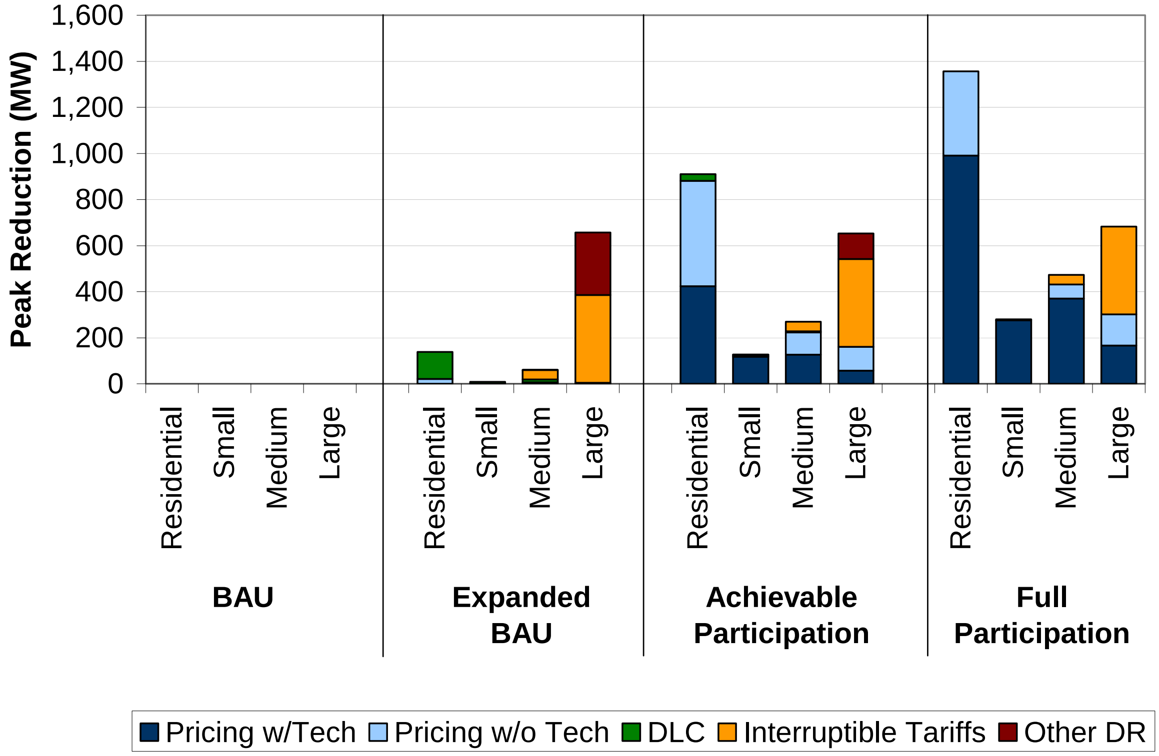
In the AP scenario (Figure 14), the inclusion of default dynamic pricing results in significantly higher demand response potential, particularly in the residential class. Acceptance of enabling technology replaces some of the participation in DLC in the EBAU scenario. As in the Georgia analysis, the Large commercial and industrial impacts are lower in the AP scenario than in the EBAU scenario. The explanation is the same in that the per-customer impacts of the new Other DR programs are larger than those of the dynamic pricing programs, and the total class potential drops in the AP scenario as a result. The total system demand response potential, however, increases to 2 GW, or nine percent of peak demand.

Figure 14: Washington BAU, EBAU, and AP Peak Reduction in 2019



Demand response potential under the FP scenario is dominated by dynamic pricing with enabling technology. Impacts from interruptible tariffs are still reported for some Medium and Large commercial and industrial customers, as customers simultaneously enrolled in these programs might be expected to provide larger reductions from the interruptible tariff. The FP potential for Washington is 2.8 GW, or 12 percent of peak demand. This is lower than that of Georgia or Connecticut, due to the lack of existing demand response and the state's low saturation of central air conditioning. Results are provided in Figure 15.

Figure 15: Washington Potential Peak Demand Reduction in All Scenarios, 2019



Summary of State Impacts

The previous three case studies demonstrate that each state has unique characteristics that will make its demand response potential different from that of other states. A comparison across these case studies has identified some of the key drivers of demand response potential. This includes:

- Central air conditioning saturation: High central air conditioning market penetration leads to larger demand response potential, because customers with central air conditioning are more responsive to dynamic pricing. Additionally, higher central air conditioning saturation means that a larger share of the population is eligible to participate in DLC programs. This is evident when contrasting residential demand response potential in Georgia and Connecticut.

- Cost-effectiveness: If a program does not pass the economic screen for a given customer class, then it will not be offered to those customers and demand response potential will be lower as a result. This was illustrated in Connecticut, where enabling technologies were not cost effective for Large commercial and industrial customers, and their dynamic pricing potential was low as a result.

- Customer mix: States with a higher concentration of load in the Residential and large commercial and industrial classes will often have higher demand response potential, as these classes tend to provide the largest per-customer peak reductions. A higher than average share of peak demand in these customer classes drives the relatively high demand response potential seen in Georgia.

- Regional price elasticity: Customers in the western U.S. have been found to be more price responsive than customers east of the Rocky Mountains. This drives regional differences in dynamic pricing potential. In Washington, customers on dynamic pricing would potentially be more responsive to dynamic pricing (on a percentage basis) than customers in more humid states in the east due to the lower loss of comfort that they would experience when reducing air conditioning load on hot summer days.[41]

- Existing program impacts: States that are reporting above-average per-customer impacts from non-pricing programs will tend to have higher total demand response potential in those programs. In other words, it is assumed that as participation in the existing programs increases, customers will continue to provide large impacts. Further, a high participation rate in existing programs will contribute to higher overall demand response potential. In particular, the ability of demand response to participate in wholesale markets increases demand response potential, as seen in the Connecticut case study.
- AMI deployment: To the extent that dynamic pricing contributes to demand response potential in the EBAU scenario, its impact is limited by the final market penetration rate of AMI under the partial deployment scenario. The rate at which AMI is deployed over time affects the amount of dynamic pricing under all scenarios.

Demand response potentials were estimated for all 50 states and the District of Columbia. Figures 16 through 19 illustrate the potential of the ten states with the highest potential in 2019 and the ten states with the lowest 2019 potential (based on the AP scenario). On a gigawatt basis, California, Florida and Texas predominate because they have the highest peak demands. Ranked by demand response potential as a fraction of peak demand, Connecticut, Maryland and Maine are highest; each has substantial amounts of existing demand response, Maine has an above-average share of peak demand in the Large commercial and industrial customer class, and Maryland has a relatively large amount of residential central air conditioning.[42] There is a significant amount of variation across the states, both in terms of demand response potential and the amount of demand response that exists today. Complete state results appear in Appendix A.

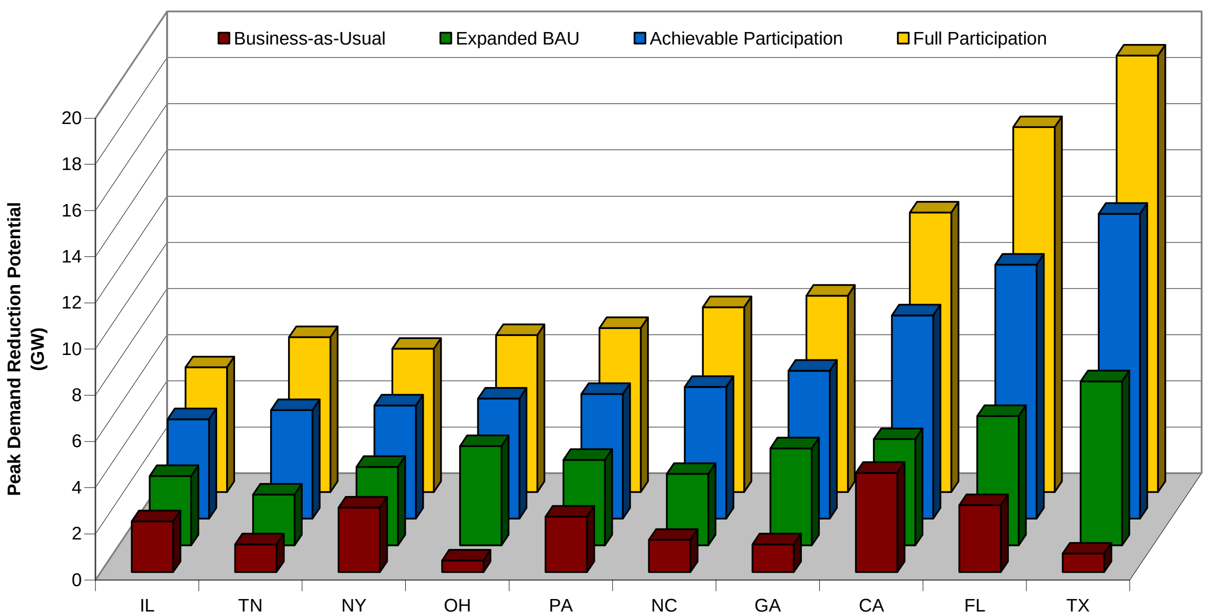


Figure 16: Top Ten States by Achievable Potential in 2019 (GW)

[41] This is based on a survey of recent dynamic pricing pilots. More detail is provided in Appendix D.

[42] Maryland is also assigned a high price elasticity based on results of Baltimore Gas & Electric Company's dynamic pricing pilot. More detail is provided in Appendix D.

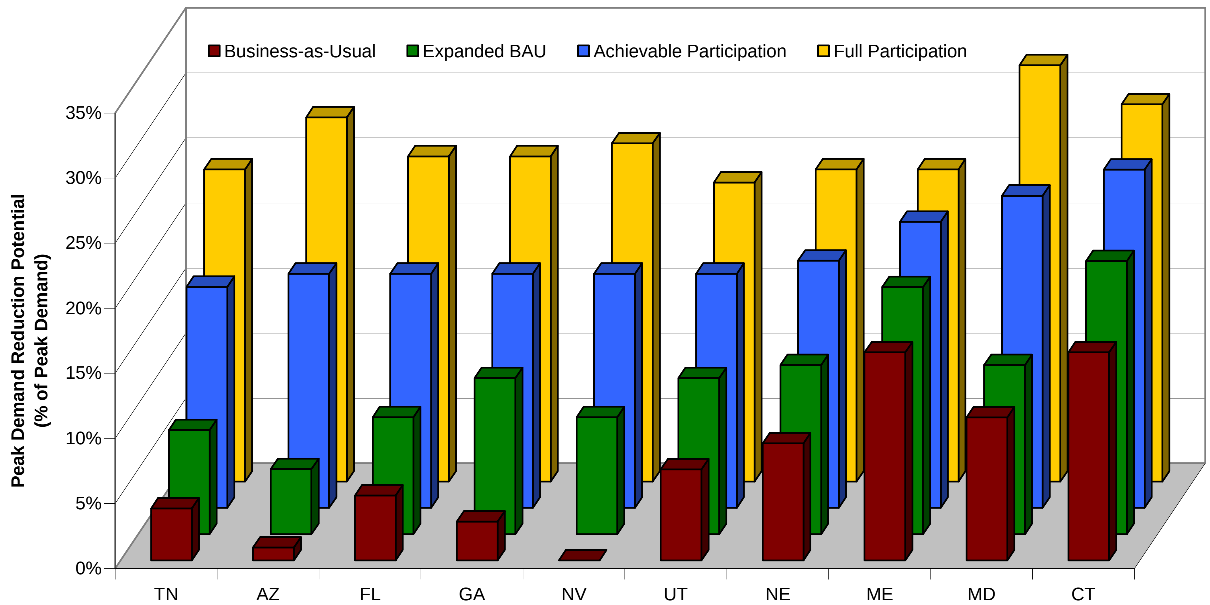


Figure 17: Top Ten States by Achievable Potential in 2019 (% of Peak Demand)

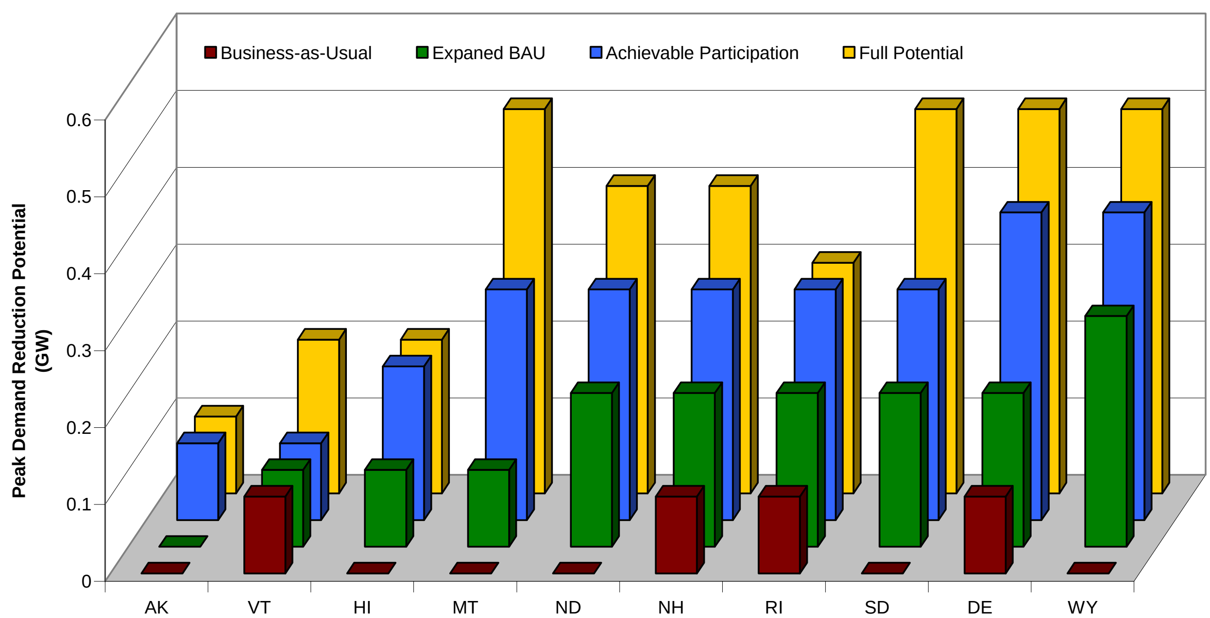


Figure 18: Bottom Ten States by Achievable Potential in 2019 (GW)

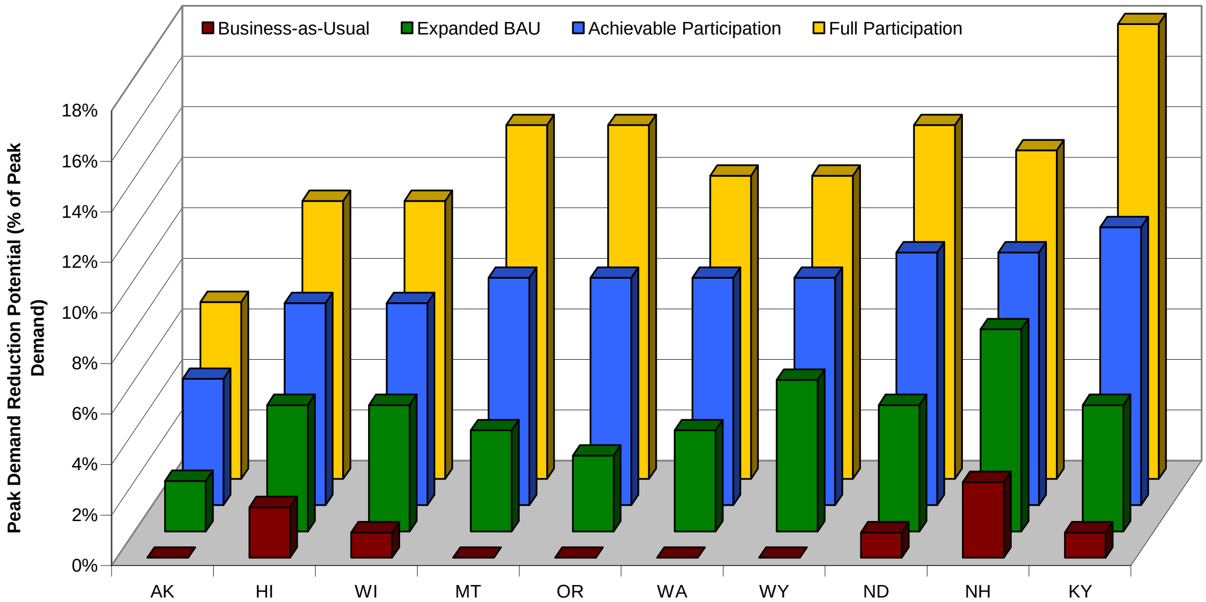


Figure 19: Bottom Ten States by Achievable Potential in 2019 (% of Peak Demand)

Benchmarking the Estimate for the Business-as-Usual Scenario

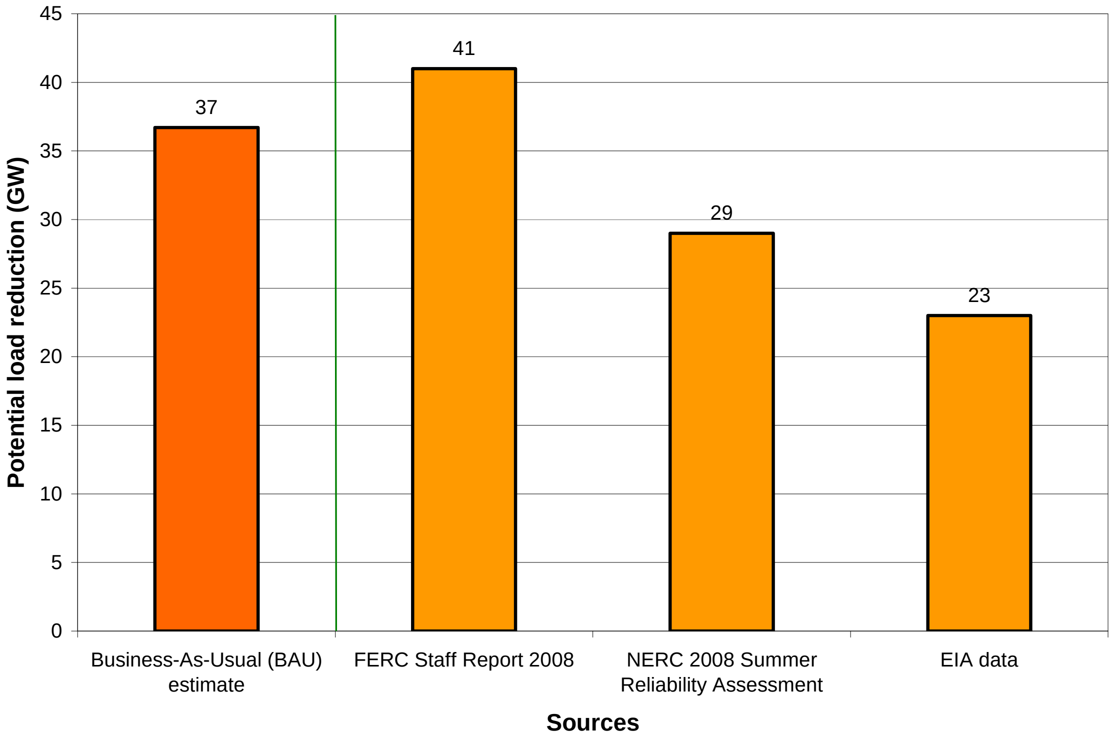
The estimate for the BAU scenario serves as the starting point for much of this analysis, so it must be carefully validated through comparisons to other available data sources. Specifically, the 2008 BAU estimate of 36.7 GW has been benchmarked against three recent estimates of existing demand response:

- *2008 FERC Assessment of Smart Metering and Demand Response* ("2008 FERC Staff Report");
- *NERC 2008 Summer Reliability Assessment*; and
- Data from the Energy Information Administration's (EIA's) Form-861 database.[43]

Figure 20 shows a comparison of the load reduction potential estimation for the BAU scenario with data from the three other sources.

[43] Table 9.2 'Demand Side Management Program Annual Effects by Program Category, 1996 through 2007', which reports a potential peak load reduction of 23.1 GW from load management programs offered by large utilities in 2007. This is based on the EIA Form-861 reporting by utilities. http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_3.pdf

Figure 20: Comparison of BAU Estimate to Other Data Sources (2008)



The BAU scenario estimate in the present analysis is based on the 2008 FERC Demand Response Survey Database which supports the staff report. The BAU potential estimate is lower than the 41 GW of potential indicated in the Staff Report and excludes two categories of programs that were included in the FERC analysis: 'Time-Of-Use (TOU)' rates and 'Back-Up Generation'; and also excludes additional state-specific adjustments (see Table 2). The reasons for excluding these three items from our BAU estimation are as follows:

1. Time-Of-Use (TOU) rates: For the purposes of this analysis, it is recognized that TOU rates can lead to significant reductions in peak demand. However, this generally happens through permanent load shifting rather than through demand response with short response time. See the discussion in Chapter II for more details on this exclusion.

2. Back-up generation: Programs that explicitly target back-up generation are not included in the BAU estimation, as back-up generation is not considered to be a demand response option by itself. But, back-up generation is included in cases where it is an underlying option in a general demand response program.

3. State-specific adjustments: An additional adjustment was made for an outlier program that is likely to have dramatically overstated impacts.[44]

[44] In the 2008 FERC survey database, a Minnesota utility, Great River Energy, reported a load reduction potential of around 50% of the total potential for the state. However, the EIA Form-861 database indicates that the summer peak load contribution from this utility was 13% of the total summer peak load for the state. We therefore adjusted the load reduction potential reported by this utility in the FERC survey database to represent approximately 13% of the total load reduction potential for the entire state. This led to a reduction of 1.9 GW of potential for the State of Minnesota (Item 3 in Table 2). This observation was confirmed through a review of Electric Power Research Institute, "Energy Efficiency Potential Assessment for Great River Energy." EPRI Technical Report 100891, July 2003.

Table 2: Explanation of Difference between FERC Staff Report and BAU Estimate

	Potential load reduction (GW)
2008 FERC Staff Report	41
1. TOU impacts	- 1.7
2. Backup generation	- 0.7
3. State-specific utility adjustment	- 1.9
BAU Estimate	= 36.7

The BAU scenario estimate is higher (by around 8 GW) than the amount of existing demand response provided in the 2008 NERC Summer Reliability Assessment report.[45] This discrepancy is most likely due to the fact that NERC's assessment is primarily focused on ISO/RTO estimates for demand response resource participation, while the BAU estimation based on FERC survey data was developed through a bottom-up estimation approach through aggregated utility reporting on demand response programs.

Lastly, the BAU scenario estimate is also substantially higher than the EIA estimate (by roughly 14 GW). This difference can be explained by the fact that the EIA estimate only includes data reported by large utilities, which leads to the estimation of a lower level of load reduction potential.

[45] In its subsequent 2009 Summer Reliability Assessment Report (May 2009) NERC reports the demand response potential for summer 2009 peak load reduction to be about 33 GW. This study estimates the BAU load reduction potential in 2009 to be 36.8 GW, higher by almost 3.8 GW than NERC's 2009 report.

CHAPTER IV. TRENDS AND FUTURE OPPORTUNITIES

This report estimates the potential for demand response in the United States at the national, regional, and state levels using four different definitions of potential. The four concepts of potential have been estimated for five program types across four customer classes. It relies on readily available information and data. As such, ideas and concepts that could not be quantified were excluded. This chapter briefly addresses some of these non-quantifiable aspects of demand response and suggests the role they may play in the future.

A wave of new technologies is emerging that falls under the broad rubric of the smart grid. At this point, these technologies are too new for their likely market penetration or impact per participating customer to be determined. These include advanced, grid-friendly appliances which communicate with each other and whose operation can be managed remotely or locally by households through a digital home energy management system. Early versions of these technologies have been shown to be very promising but also very expensive in the California statewide pricing pilot and the Olympic Peninsula pilot. It is important to keep an eye on the continued development, testing and consumer acceptance of these technologies.

Increasingly sophisticated in-home displays are being introduced that have the potential to reduce overall energy consumption. Future versions will be able to estimate how much of the bill was spent on the major end-uses, giving customers essential information to prioritizing their energy use during expensive times. These devices have the potential for lowering customer peak demands, thereby contributing indirectly to demand response. Some of these devices can work with time-of-use rates and future variants will probably be able to work with dynamic pricing rates.

In a similar vein, new pricing designs continue to be developed that can enhance the appeal of dynamic pricing to large numbers of customers by tailoring the risk-reward trade-off inherent in such rates to the preferences of individual customers. For example, various types of real-time pricing products are under consideration featuring either a two-part structure in which customer-specific baseline usage is priced at the existing rate and only usage that deviates from the baseline is priced through real-time rates. Other products are being introduced where customers buy a price-cap to insulate all their usage from excessive levels of price volatility. Other examples include variable peak pricing rates under which prices on critical days are not pre-specified but based on real-time costs in wholesale markets and dynamic pricing rates where, for a fee, customers can over-ride the price signal on certain days that are important to their business.

Today, codes and standards instituted by federal and in many cases state agencies affect energy used by appliances and by buildings. They are not designed to affect peak demand. However, that could change if agencies began to set standards for demand response. For example, the California Energy Commission is considering “load management” standards that may require all new Residential and Small commercial and industrial buildings to come equipped with programmable communicating thermostats.

Another trend that is beginning to be observed in states with large energy efficiency and demand response programs is the desire to integrate these two program offerings. The idea is that ultimately both involve the same customer and often the same end-uses. To promote faster adoption of both programs, the value proposition has to be conveyed clearly to customers and the actions required of them have to be streamlined. The combined effect of integrated programs on demand response could be significant. Future assessments should address this.

Distributed energy resources, such as photovoltaic arrays mounted on roof tops, hold the potential for having a significant effect on peak demand. Currently, their high capital cost poses a barrier to rapid market penetration. However, federal and state policies are addressing the cost barrier. As economies of scale increase, the cost should go down. When combined with appropriate rate designs, such as time-of-use rates, the impact of these dispersed resources on peak loads could be significant. Other examples include battery storage and thermal energy storage. Both items hold the potential to significantly reduce peak demand on a permanent basis by shifting it to off-peak periods. As in the case of photovoltaic arrays, cost is a significant barrier to their rapid market penetration today. Another example is behind-the-meter generation which includes a diverse set of technologies including small conventional generation units that are used as back-up generation during emergencies and cogeneration systems that combine heat and power, largely in industrial process applications.

Finally, another development to watch is the introduction of plug-in hybrid vehicles (PHEVs). If PHEVs can be charged during off-peak hours, they can improve capacity utilization in the power system and lower costs for all customers. However, if they are charged during peak hours, the load factor will worsen. The penetration of PHEVs will depend on several unknowns, including the price of gasoline, the price of electricity, customer driving habits and the incremental cost of PHEVs over conventional gasoline-power vehicles based on the internal combustion engine.

Time-of-use (TOU) rates are not considered a form of demand response in this report because they cannot be used to produce reductions in peak demand during critical periods. However, they do represent a way of reducing peak demand over the long-run and reducing the need for peaking generation units. While TOU rates have been in existance for a long time, their penetration of the market, especially for Residential and Small commercial and industrial customers, has been limited. There are two major limitations. The first one is that the peak period encompasses far too many hours to allow customers an opportunity to curtail usage during that period or to move it to off-peak periods. The second one is that the price differential between the peak and off-peak periods is not big enough to create significant savings opportunities. Both are being addressed in the TOU rate designs that are now being introduced by several utilities. Of particular interest is the idea of a super peak period which may be as narrow as three hours and which may be applied only during the two or three months of the summer where the system is likely to peak.

Another set of influences that will shape the future of demand response are utility and ISO/RTO administered energy efficiency programs. Many of these programs target end-uses such as central air conditioning which are a major driver of system peaks. As these appliances become more efficient, peak loads may diminish, albeit not by the same percentage amount as overall energy consumption. Similar comments can be made about inclining block rates which charge higher rates for usage in the upper tiers. Since that usage is highly correlated with the operation of peak-inducing appliances, reductions in upper tier usage brought about by inclining block rates can also lower peak demands.

Technology-enabled demand response programs can be activated on short notice and have the capability of providing ancillary services in restructured wholesale markets. There is insufficient evidence on whether demand response is being actively used in this fashion in ancillary service markets. Experience to date is largely limited to energy and capacity markets. However, this will change in the future as ancillary service markets are opened to demand resources.

Areas for Further Research

This study has relied upon the best available data to make projections of demand response potential. For example, several pilots with dynamic pricing rates have yielded results that have been used to inform the study's assumptions about likely customer response to such pricing programs. This required making some assumptions about the impact of humidity on customer response, as predicted from PRISM[46] that

[46] The California Statewide Pricing Pilot produced estimates of price elasticity for residential customers that captured variations in customer price responsiveness across four different climate zones in the state. These estimates were codified in the Pricing Impact Simulation Model (PRISM) which allows price elasticities to vary as a function of a zone's saturation of central air

was estimated using data from California's dynamic pricing pilot. It would be worthwhile to test the validity of this assumption by combining the data from the various pilots.

There is a long history with utility direct load control programs for Residential and Small commercial and industrial customers and curtailable/interruptible tariffs for Large commercial and industrial customers. Results from these programs have been used to inform this study's assumptions. However, in several areas, further research is warranted to improve the quality of the assumptions. Many of these deal with Large commercial and industrial customers. For example, there is need for much better information on the likely effect of automated demand response on peak loads and the response of these large customers to dynamic pricing rates.

As noted earlier, not much is known about the impact of dual-purpose programs that combine energy efficiency with demand response. More research is needed on this topic.

Most of these gaps in knowledge can be addressed by designing and implementing pilot programs. These pilots should focus on topics on which not much is known today and not repeat investigations that have already been carried out. It would be useful to conduct a pilot screening exercise to identify high priority areas. One approach to doing this is to focus future pilots on areas which simultaneously satisfy two criteria: (a) high potential savings and (b) high uncertainty (for example, where newer technologies are involved). Areas with low potential may not be worth piloting. Areas with high potential savings but low uncertainty do not require piloting and should instead be considered for full-scale implementation. The lowest priority should be given to areas with low potential savings and low uncertainty.

Another area in which further research is needed involves the prediction of customer participation rates. For certain programs with long histories, such as direct load control and curtailable/interruptible rates, considerable information on customer participation rates is available. Information from the distribution of participation rates has been widely used in this study. In other areas, such as customer participation in dynamic pricing programs, relatively little is known. New work is needed in this area. The traditional type of impact evaluation pilots will not help address the issue. Market research involving customer surveys, conjoint analysis and discrete choice modeling can provide initial answers. But all of these rely on stated preferences rather than observed (or revealed) preferences. Other creative research methodologies will need to be developed that combine information on stated preferences with information on revealed preferences (where it is readily available or where it can be inferred by analogy).

conditioning equipment and weather conditions. For more information, see Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report.* March 16, 2005

CHAPTER V. OVERVIEW OF MODELING AND DATA

This chapter provides an overview of the model and data that underlie the demand response potential estimates presented in prior sections and in the detailed, state-level summaries contained in Appendix A. The chapter is divided into the following subsections:

- High-level summary of modeling methodology
- High-level summary of data development
- Cost-effectiveness methodology

Model Overview

Development of the demand response potential model and default data underlying the estimates presented in this report was guided by the following objectives:

- Produce defensible estimates of demand response potential based on the definitions and assumptions underlying this analysis;
- Develop internally consistent estimates of demand response potential at the state, regional and national level;
- Provide defensible default data for all required model input variables at the state level, from publicly available sources;
- Ensure that there is no double counting of demand response load impacts;
- Provide a user friendly, extremely flexible model that can be used to update the estimates as better data become available, as policies change, and to aid in policy analysis and development.

Demand response potential estimation is inherently a "bottom-up" process. Load impacts associated with demand response programs are fundamentally driven by changes in consumer behavior, and demand response potential and load impacts vary significantly across customer segments. For example, the extensive literature on electricity demand developed over the last 30 years, and more recent evidence from time-based pricing pilots, indicates that residential customers are more responsive to time-varying price signals than are commercial and industrial customers (e.g., residential customers have higher price elasticities than do non-residential customers).[47] On the other hand, the average commercial and industrial customer has larger loads than does the average residential customer, so smaller percentage impacts still often translate into larger absolute impacts on a per customer basis. Residential customer impacts vary significantly across customers with and without central air conditioning and, for customers with central air conditioning, potential impacts vary across climate regions. These are a few examples of why it is important that the development of demand response potential estimates start at the customer level and work up to the segment and region level of interest.

There are three fundamental building blocks needed to estimate demand response potential:

[47] See, for example, Charles River Associates. *Impact Evaluation of the California Statewide Pricing Pilot, Final Report,* March 16, 2005 and Stephen S. George, Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*. Final Report, June 28, 2006.

- An estimate of average energy use during peak periods before demand response impacts take effect;
- An estimate of the change in energy use during peak periods resulting from customer participation in demand response programs and response to demand response price signals or incentives; and
- An estimate of the number of customers that participate in demand response programs.

These three building blocks are displayed in the blue shaded boxes in Figure 21 which also illustrates some of the primary input values that are needed to predict demand response effects.

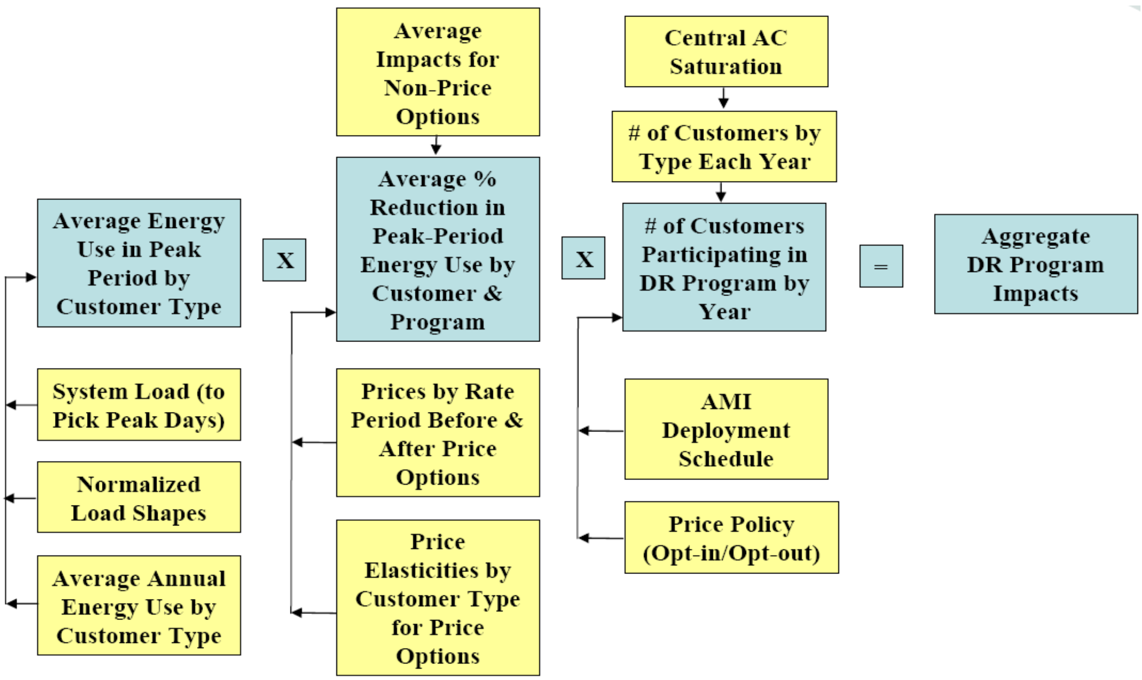


Figure 21: Key Building Blocks and Inputs for Demand Response Potential Model

A significant challenge in developing demand response potential estimates is the general lack of data on energy use during peak periods, when demand response is needed most and the benefits are greatest. Most utilities do not have hourly load data for a representative sample of customers and the lack of such information can be a stumbling block for developing demand response load impacts for utilities and states. Original work was done through this project to develop representative, hourly load data to use as input to the model for five customer segments: residential consumers with and without central air conditioning, small non-residential consumers (demands less than 20 kW), medium non-residential consumers (demands between 20 and 200 kW) and large non-residential consumers (peak demands exceeding 200 kW). These load estimates were developed using regression analysis based on hourly load data from utilities in 21 states, representing a broad cross section of customer segments and climate conditions. Normalized load shapes were developed using statistical analysis and combined with annual energy use, weather data and system load data (to identify top system load days) from each state to produce the starting values for energy use during peak periods depicted in the first blue box in Figure 21. These estimates are primarily used as input to load impact estimates for price-based demand response. This original work could be a valuable resource for states and utilities that want to refine the demand response potential estimates presented here or that might find hourly load data useful for demand response program planning or other purposes.

The demand response potential model uses two different approaches for determining load impacts for various demand response options. Load impact estimates for non-price based demand response options, such as direct load control and interruptible rates, are based on average values determined through analysis of data from existing programs. Load impact estimates for price-based demand response are determined using the normalized load shapes summarized above and estimates of the percentage change in energy use during peak periods based on price elasticities and the assumed change in prices during peak periods for demand response tariffs relative to non-time varying rates.

Price elasticities depict the percentage change in energy use given a percentage change in price. In recent years, there have been numerous studies done by utilities around the country that estimate price elasticities associated with time-based pricing.[48] Estimates from various studies were used here to determine price impacts that vary across states and customer segments based on key drivers of demand response, such as air conditioning saturation, climate and the presence or absence of enabling technology such as programmable communicating thermostats that can help to automate some forms of price response in regions where the technology is cost effective.

The percent reductions for price based demand response options used in each scenario are based on an assumption that prices during the peak period on high demand days are eight times higher on a dynamic time-varying rate than they are based on the average price associated with the non-time varying, otherwise applicable tariff.[49] This price ratio is intended to depict the ratio between an average price and a dynamic price that incorporates a large portion of the avoided cost of capacity[50] into the small number of hours in which peak-period dynamic price signals are in effect. In reality, price ratios could vary significantly across states if every state fully reflected the avoided cost of capacity in the dynamic rate, since the avoided capacity cost does not vary greatly across states but current average prices do. As such, the price ratio might be much higher in Idaho, for example, where current prices are relatively low, than it would be in California, where current prices are much higher.[51] However, tariff design is not just based on cost analysis—there is always a concern about extreme changes in prices whether or not they are cost-reflective. As such, using the same 8 to 1 price ratio across states may more accurately reflect how prices might evolve as they move closer to reflecting both avoided capacity costs and other requirements to be reflected in a rate design.

The third key element of demand response potential estimation is the number of customers that participate in each demand response program. The number of participants is a function of the number of eligible customers and the assumed participation rate. The number of eligible customers is based on the number of customers by segment and, in some cases, to the number of customers with specific end use equipment, such as central air conditioning.[52] For residential customers, the breakdown between those with and without central air conditioning is determined from data on air conditioning saturation in each state. The eligible population for price based demand response options is also driven by the presence or absence of

[48] A useful summary of numerous pilots is contained in Ahmad Faruqui and Sanem Sergici, "Household response to dynamic pricing of electricity: A survey of the experimental evidence," January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf. Price elasticities determined from a large, multi-year experiment conducted in California formed the starting point for the values used in the demand response potential model. These values are documented in Stephen S. George and Ahmad Faruqui, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report.* March 16, 2005 and in Stephen S. George, Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*. Final Report, June 28, 2006. These starting values were modified, as discussed in Appendix D, based on information from other pilots and variation in key drivers of demand response such as air conditioning saturation and climate.

[49] The price ratio used for the large C&I customer segment is 5 to 1. This lower ratio is based on the fact that most large C&I customers are already on static time-of-use rates and, thus, have a higher peak-period price as part of their standard tariff than do other customers. As such, the ratio between the standard (TOU) peak price and a price that more fully reflects the avoided capacity cost is less for this customer group than it is for the other customer segments.

[50] "Avoided cost of capacity" refers to the amount of investment in new power plants that could be avoided or deferred through a reduction in peak demand.

[51] A recent rate filing by PG&E that reflects the full avoided cost of capacity in critical peak price hours has a peak period price of roughly $1.50/kWh for residential customers. This represents roughly a 10 to 1 price ratio compared to current average prices in CA but a state like Idaho, it would be closer to 20 to 1.

[52] Central air conditioning is a necessary condition to participate in air conditioning load control programs and also for the technology-enabled price responsive demand response options.

advanced metering infrastructure (AMI), which varies across years and scenarios. The number of customers assumed to participate in a demand response program is based on the assumed pricing policy (e.g., whether dynamic pricing is mandatory, is based on default, opt-out enrollment policies, or is based on opt-in enrollment). Enrollment assumptions for other demand response programs are based in part on enrollment in "best practices" programs that currently exist.

Much more detailed documentation of the model and input values is contained in Appendix E. The demand response potential model used to generate the estimates contained in this report is available from FERC. It was developed with the idea that state and utility policy makers may wish to use the model with different input data and assumptions to develop alternative, state-specific demand response potential estimates.

The demand response potential model is an Excel spreadsheet tool that contains user friendly drop-down menus that allow users to easily change between demand response potential scenarios, import default data for each state, and change input values on either a temporary basis for use in "what if" exercises or on a permanent basis if better data are available. Figure 22 shows half of the front-end, user input page of the spread sheet where scenarios can be selected and input values changed. Figure 23 shows the second half of the same input sheet. These "screen shots" are examples for a specific state and are shown here simply to give the reader a quick perspective on how input values can be changed and new scenarios created. Detailed documentation of the model and all variable names and input values are contained in Appendices D and E.

As seen in Figure 22, the first part of the input sheet contains pull-down menus that can be used to select the geographic region of interest (each of 50 states plus D.C., 9 census regions and the nation as a whole) and the demand response potential scenario (Business-as-Usual, Expanded BAU, Achievable Participation or Full Participation potential). The user can also select from among a wide range of price ratios (and differing ratios for each customer segment) that drive price-based demand response load impacts. Once these selections are made, the "Load Default Inputs" button is used to load the default data from the state-level database that pertains to the options selected. If the user changes input values in the other portions of the database through the input screen, the "Save As Default" button can be used to make those changes permanent.

The lower portion of Figure 22 shows the input values used by demand response program type and customer segment. Many of these values are either loaded in from the default database or are user defined. The line labeled "Customers with load suitable for enabling technology" is tied to the saturation of central air conditioning in each state and customer segment, as this value determines the percent of total customers where programmable communicating thermostats or direct load control options apply. The next line, "Offered Technology" is a function of whether such technology is determined to be cost effective in that state. This is typically 100 percent or 0, the latter being used in states where the particular technology is not cost effective. As indicated previously, all of the variables shown in Figure 22 are documented in the appendices. Figure 23 shows the remaining portion of the input sheet from the model. The top part contains input values for the number of customers by type and growth rates for the number of customers, peak demand and energy use. It also shows the AMI deployment schedule for each customer segment. The bottom part of this portion of the input sheet has values for the remaining key variables that drive load impacts. They include average use during the peak period by customer segment, and percent reductions in average use for customers who participate in various demand response options. The percent reductions for price-based demand response are based on the price elasticities underlying the default database and the assumed price ratios that drive each scenario. However, these values can be overridden by the user if, for example, there is more current or relevant data from a pricing pilot at a specific utility or state indicating that the estimated values based on the default price elasticities might be inappropriate for the scenario of interest to a specific user.

The demand response potential model produces a wide variety of numeric and graphical output reports and files. The graphs and tables shown in each of the state reports contained in Appendix A are examples of a few of the model outputs. In general, tables and/or graphs are produced that show the breakdown of demand response impacts (in both absolute and percentage terms) by program type, customer segment, and year under each of the four demand response potential scenarios. The model also creates a database containing all output values with built in pivot tables that can be used to easily manipulate the data and to produce customized output tables and figures. There are also output files and graphs that show the results for all four demand response potential scenarios in the same sheet.

Figure 22: User Friendly Input Sheet from Demand Response Potential Model

FERC National DR Potential Assessment

SCENARIO INPUTS - GA Achievable

State	GA	
Type of Potential	Achievable	
New Peak to Old Peak Price Ratio - Residential	8.00	
New Peak to Old Peak Price Ratio - Small C&I	8.00	
New Peak to Old Peak Price Ratio - Medium C&I	8.00	
New Peak to Old Peak Price Ratio - Large C&I	5.00	
Data from year	2008	

Load Default Inputs

Instructions

Save As Default Inputs and Results

Update Results Database (Cycles through 50 States)

DR TYPE SPECIFIC INPUTS	Residential	Commercial & Industrial Small	Commercial & Industrial Medium	Commercial & Industrial Large
Dynamic Price Induced DR				
Max Percent Enrolled or Notified	75.0%	75.0%	60.0%	60.0%
Rates become effective at (% AMI penetration)	0.0%	0.0%	0.0%	0.0%
Enabling technology				
Customers with load suitable for enabling technology (%)	82.2%	78.0%	85.0%	40.0%
Offered technology (% of eligible)	95.0%	95.0%	95.0%	95.0%
Accept technology (%) - used for achievable	60.0%	60.0%	60.0%	60.0%
Automated or Direct Control DR				
Current Market Penetration (% of eligible customers)	2.8%	0.3%	0.0%	0.0%
Max Market Penetration (% of eligible customers)	25.0%	1.2%	7.2%	0.0%
Years required to achieve max penetration	5.0	5.0	5.0	5.0
Interrutiple Tariffs				
Current Penetration (% of customers in segment)	0.0%	0.0%	0.0%	6.5%
Current Penetration (% of MW in segment)	0.0%	0.0%	0.0%	4.9%
Max Penetration (% of customers in segment)	0.0%	0.0%	0.3%	6.9%
Max Penetration (% of MW in segment)	0.0%	0.0%	1.7%	16.8%
Years required to achieve max penetration	5.0	5.0	5.0	5.0
Other DR Programs				
Current Penetration (% of customers in segment)	0.0%	0.0%	0.0%	0.2%
Current Penetration (% of MW in segment)	0.0%	0.0%	0.0%	1.1%
Max Penetration (% of customers in segment)	0.0%	0.0%	0.1%	18.9%
Max Penetration (% of MW in segment)	0.0%	0.0%	0.0%	23.4%
Years to achieve max penetration	5.0	5.0	5.0	5.0

Figure 23: User Friendly Input Sheet from Demand Response Potential Model (continued)

	J	K	L	M	N	O
4						
5				Commercial & Industrial		
6	GENERAL INPUTS		Residential	Small	Medium	Large
7	Population and Load Growth Factors					
8	Starting Customer Population		4,039,005	483,576	66,628	11,363
9	Population Growth Rate (Annual)		1.29%	1.57%	1.57%	1.57%
10	Annual Consumption Growth (Annual)		1.24%	1.13%	1.13%	1.13%
11	Critical Peak Growth (Annual)		0.60%	0.33%	0.33%	0.33%
12	AMI Deployment					
13	2009		10.7%	10.7%	10.7%	10.7%
14	2010		21.5%	21.5%	21.5%	21.5%
15	2011		32.2%	32.2%	32.2%	32.2%
16	2012		43.0%	43.0%	43.0%	43.0%
17	2013		53.7%	53.7%	53.7%	53.7%
18	2014		57.5%	57.5%	57.5%	57.5%
19	2015		61.2%	61.2%	61.2%	61.2%
20	2016		70.0%	70.0%	70.0%	70.0%
21	2017		80.0%	80.0%	80.0%	80.0%
22	2018		90.0%	90.0%	90.0%	90.0%
23	2019		100.0%	100.0%	100.0%	100.0%
24						
25						
26						
27				Commercial & Industrial		
28	AVERAGE PARTICIPANT CRITICAL DAY LOAD AND LOAD RED		Residential	Small	Medium	Large
29	Critical peak avg. hourly load (kW)		3.36	5.44	59.68	601.70
30	Critical peak avg. hourly load - CAC owners (kW)		3.73	DNA	DNA	DNA
31	Critical peak avg. hourly load - no CAC (kW)		1.63	DNA	DNA	DNA
32	Pricing - customers without central a/c (% reduction)		8.5%	0.7%	8.7%	7.5%
33	Pricing - customers with central a/c but no enabling tech (% redu		19.3%	0.7%	8.7%	7.5%
34	Pricing - customers with central a/c and enabling tech (% reducti		33.8%	14.9%	13.9%	13.9%
35	Automated or Direct Load Control DR (kW reduction per custon		1.24	2.48	7.44	37.18
36	Interruptible Tariffs - (% reduction)		0.0%	0.0%	69.9%	94.5%
37	Other DR - committed load reduction programs (% reduction)		0.0%	0.0%	39.4%	50.0%

Database Development

Each of the data elements that contribute to the model inputs were developed through careful review of a number of publicly available data sources. Table 3 lists the data elements developed and the sources used for developing these elements. Appendix D to the report describes in detail how the different data elements were developed and the interrelationships between the different elements and the sources. Appendix B details the challenges of developing state level data for this Assessment.

Table 3: Summary of Key Data Elements and Sources

Data Category	Data Elements	Data Sources
Market Characteristics Data	Number of customer accounts by rate class	• EIA State-Level data • FERC Form No. 1 database
	Electricity sales by rate class	• EIA State-Level data • FERC Form No. 1 database
	System peak load forecast by state	• 2008 NERC Long Term Reliability Assessment report • EIA State-Level data
	Average Peak Load per customer by rate class	• Utility/ISO system load data • Hourly load shapes by state • CAC saturation • Average energy use by customer segment • State weather data
	Growth rate in per customer peak load	• U.S. Census Bureau • Supplemental Tables to Annual Energy Outlook 2008
	Central air conditioning market saturation data	• Utility and state level appliance saturation survey reports • Direct utility contacts • EIA data on Regional Energy Consumption Survey (RECS) • American Housing Survey, U.S. Census Bureau • EIA data on Commercial Building Energy Survey (CBECS)
	AMI deployment schedule by state	• KEMA report • FERC survey • Utilipoint • Enernex
Demand Response Program Related Data	Business-As-Usual demand response potential estimation	• 2008 FERC demand response Survey data
	Current participation in demand response programs	• 2008 FERC Demand Response Survey data • Demand response program evaluation reports • Direct contacts with utilities
	Demand response program impacts	• 2008 FERC Demand Response Survey data • Demand response program evaluation reports • Direct contacts with utilities

Development of Load Shapes

One of the key inputs to demand response potential estimation is average electricity use per customer per hour during time periods when demand response programs are likely to be used but before any demand response occurs. We refer to the time period representing when demand response has a high probability of being used as the "peak period" on a "typical event day" and represent that period by the hours between 2 and 6 pm on the top 15 system load days in each state.[53] Note that average energy use across the top 15 system load days will produce demand response load impact estimates that are significantly lower than if they were based on the single hour of system peak or based on fewer than the top 15 system load days. Utility system load data were used to identify top system load days in each state.

As previously discussed, hourly load data were not available for all utilities and states or for all customer segments within states. Indeed, no data at all were found that distinguished between residential customers with and without central air conditioning. Fortunately, hourly load data were available on a large enough cross section of utilities and states (21 states in total) that it was possible to use regression analysis to estimate normalized load shapes for each relevant customer segment and to use these models to develop load shapes for all other states and customer segments. Data from these utilities were used to estimate regression models that relate normalized hourly load to a variety of variables that influence load in each hour, including weather, central air conditioning saturation and seasonal, monthly, day-of-week and hourly usage patterns. This statistical analysis was used to separate weather sensitive and non-weather sensitive load for residential customers. The normalized load shapes were then combined with estimates of average annual energy use and central air conditioning saturation by customer segment for each state and state-specific weather data to produce hourly load estimates for each customer segment and state. The average, hourly energy use between 2 and 6 pm on the top 15 system load days was used as the basis for estimating load impacts for price-based demand response options for each customer segment.

AMI Deployment

Advanced metering is a necessary technology to support price-responsive demand response for mass-market customers. As such, estimates of the penetration of AMI must be developed for each demand response potential scenario. However, having advanced meters is a necessary but sufficient condition to support price-responsive demand response—a utility also needs a meter data management system and billing system that will support price-responsive demand response options. Quite often, utilities install meters that qualify as advanced meters in that they gather hourly or sub-hourly data daily, but use them as an automated meter reading system to produce monthly meter reads—they do not install the meter data management system and billing systems needed to support wide scale price-responsive demand response. The AMI deployment scenarios described below recognize that more than just metering is needed to support price-responsive demand response. The deployment time lines for each scenario are based on the understanding that only systems that have MDMS and billing systems are considered AMI for purposes of supporting demand response potential.

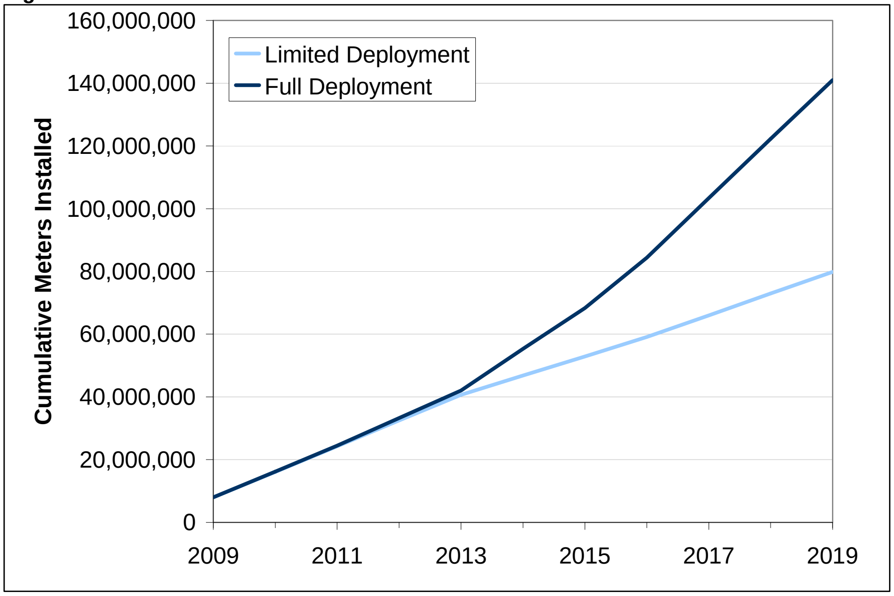
Two AMI deployment scenarios were developed for each state.

- The "Full Deployment" scenario is used to support the Achievable Participation and Full Participation demand response scenarios and assumes that all utilities will have AMI meters in place for all customers, along with the MDMS and billing systems required to support price-based demand response, by the end of the analysis horizon, 2019. Deployment timing is based on a set of assumptions described in Appendix D, and varies significantly across states based on current plans, the mix of utilities in each state, and other factors.
- The "Partial Deployment" scenario is used to support the Expanded BAU potential scenario and includes AMI deployment plans for each state based largely on a continuation of current trends. It includes utilities that already have or are currently deploying AMI systems and other utilities that, based on a variety of data sources, have expressed interest in or are believed to have a higher probability of installing such systems over the next ten years.

The following figure shows the cumulative number of AMI meters underlying the partial and full deployment scenarios.

[53] In recent AMI business cases and dynamic pricing pilots, the number of load days used varies roughly between the top 10 and top 20 days. The top 15 days were used in this study as an approximate midpoint.

Figure 24: Cumulative AMI Installations under Two Scenarios



These two alternative scenarios should not be considered forecasts of actual AMI meter and system deployment. The full deployment scenario is predicated on the assumption that all customers will have smart meters by the end of the ten-year forecast horizon. This assumption is combined with a variety of information and assumptions that drive the likely sequence of installations across utilities in a state and across states that are described below. The partial deployment scenario is probably closer to what might actually occur, but it is not a true forecast, since a true forecast would require conducting business cases on hundreds or perhaps thousands of utilities and an assessment of the likely barriers to deployment in each state. Such work was beyond the scope of this analysis.

Estimating the Impact of Dynamic Prices

The AP and FP potential estimates rely heavily on price-based demand response options, specifically on dynamic tariffs that deliver high price signals on relatively few high-demand days when demand response benefits are greatest. Estimates of the load impact associated with pricing options are based on variables known as price elasticities. Economists define the "own" price elasticity as the percentage change in the quantity purchased of a good or service divided by the percentage change in the price of that good or service. There is a similar concept, known as the elasticity of substitution, which summarizes the relationship of two goods or services that are substitutes for each other. The elasticity of substitution is equal to the percentage change in the ratio of the quantities purchased of two goods to the ratio of the prices of the two goods. Put another way, the elasticity of substitution summarizes the rate at which consumers substitute one good for another based on the relative prices of the two goods.

In the case of electricity demand, if prices are higher at one time of day relative to another, consumers may be willing to shift their load from the high priced to the low priced period. An example would be a consumer shifting the timing of their laundry from the peak to the off peak period. Alternatively, or in addition, a consumer might just forgo some energy use during the high price period. An example would be switching off lights during high priced periods—consumers don't use more lighting during low priced periods because they used less during high priced periods.

One approach to estimating how electricity demand would change in response to time varying prices involves estimating a two-equation demand system, where one equation determines the rate at which consumers substitute off-peak energy use for peak-period energy use and the second equation estimates the overall demand for energy. In combination, the two equations can predict the change in energy use in each time period as consumers move from non-time varying to time-varying prices. This is the approach that underlies the estimates of time-based price response in the demand response potential model.

A variety of pricing experiments and other studies have been conducted that allow for estimation of demand models and price elasticities such as those described above. These studies show that price responsiveness for residential customers varies across regions based in part on differences in the use of air conditioning. Climate differences can also impact price responsiveness, as can the presence or absence of enabling technology such as programmable communicating thermostats and other load control devices. Price responsiveness also differs between residential and non-residential customers with residential customers generally being more price responsive than non-residential customers. These factors have been taken into account in developing estimates of price response that reflect variation in the characteristics of customers across states. More detail on these regional factors is provided in Appendix D.

The price elasticities summarized above for residential customers produce quite different percent reductions across states as a function of the variation in climate and air conditioning saturations. There are also differences in the estimated percent reduction in peak period energy use based on differences in the assumed ratio of prices during the peak period. The following table shows the percent reduction in peak period energy use for residential customers for two price ratios for each of three states that vary with respect to central air conditioning saturation and climate. Note that the relationship between price and energy use is not linear. That is, while the price ratio doubles going from 4 to 1 to 8 to 1, the percent reduction in peak demand increases by less than 100 percent. For example, the doubling of the price ratio in Massachusetts leads to a 58 percent decrease in peak period energy use.

Table 4: Percent Reduction in Peak Period Energy Use for Residential Customers in Selected States

State	CAC Saturation	Percent Peak Period Reduction for 4 to 1 Price Ratio	Percent Peak Period Reduction for 8 to 1 Price Ratio
Massachusetts	12.70%	6.20%	9.83%
Maryland	78.00%	12.56%	19.66%
Arizona	86.80%	14.28%	22.33%

Key Assumptions

The products of the previously described data collection and modeling approach are participation rates and impacts by program type, class, and state. These form the basis for the demand response potential estimates. Summary values of participation rate assumptions for non-pricing programs in the three potential scenarios are provided in Table 5.[54] Note that program participation is expressed as a percentage of the eligible population, which changes by scenario as the role of pricing programs changes. Participation rates in Table 5 represent the 75th percentile of participation in existing programs at the state-level.[55] The 75th percentile was chosen as the "best practices" estimate because it represents the participation rate that a state would need to achieve to be a "top quartile performer" which is a metric commonly used to identify best practices in potential studies. States with participation rates higher than the 75th percentile are assumed to remain at existing levels, rather than derated to the 75th percentile.

Table 5: Final Participation Rates for Non-Pricing Programs

	Residential	Small C&I	Medium C&I	Large C&I
Direct Load Control	25%	1%	7%	N/A
Interruptible Tariffs	N/A	N/A	2%	17%
Other DR	N/A	N/A	0%	19%

Assumptions driving the final participation rate in pricing programs for the three demand response potential scenarios are provided in Table 6. Ranges reflect differences across states.

[54] BAU participation rates span a broad range encompassing these best practices estimates and are provided in Appendix D.

[55] The assumed participation rate for residential DLC is higher than the 75th percentile. This assumption is based on general industry experience with these programs and a proven history of utilities consistently being able to achieve participation rates of 25 percent of the eligible population.

Table 6: Drivers of Final Participation Rates for Pricing Programs

	Expanded BAU	Achievable Participation	Full Participation
Residential			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	75%	100%
Percent of Customers Eligible for Enabling Tech	3% to 91%	3% to 91%	3% to 91%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Small C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	75%	100%
Percent of Customers Eligible for Enabling Tech	70% to 78%	70% to 78%	70% to 78%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Medium C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	60%	100%
Percent of Customers Eligible for Enabling Tech	79%	79%	79%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Large C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	5	5	5
Final Enrollment in Dynamic Pricing	5%	60%	100%
Percent of Customers Eligible for Enabling Tech	40%	40%	40%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%

As stated in the definition of the potential scenarios, AMI market penetration is assumed to reach 100 percent by 2019 in both the AP scenario and the FP scenario. Final AMI market penetration is lower in the EBAU scenario, in which only those utility AMI deployments that were deemed "likely" through a review of industry data are included.

The assumed price ratio of 8-to-1 for Residential, Small commercial and industrial, and Medium commercial and industrial customers is driven by the range of rates tested in recent dynamic pricing pilots, some of which have been greater than 10-to-1.[56] For Large commercial and industrial, the price

[56] The PSE&G residential pilot program price ratio was 14-1o-1. BGE recently tested price ratios of roughly 9-to-1 and 12-to-1.

ratio is lower to account for the fact that many of these customers are already enrolled on TOU rates, the impacts of which would be reflected in the load forecast.

The assumptions for participation in price-based demand response options are based on market research and the limited experience that has been gathered to date. For the EBAU scenario, a participation rate of five percent is used for all sectors. There is very little experience and research to date upon which to base these assumptions. The most recent experience for a dynamic rate for residential customers has to do with Pacific Gas & Electric Company's SmartRate tariff, which is a critical peak pricing tariff that was offered in 2008 to residential customers in the part of the PG&E service territory where AMI meters had been installed.[57] The program was offered through direct mail and roughly eight percent of customers enrolled after a single mailer. Thus, five percent could be quite conservative for a program that would be marketed over an extended period of time. Given the limited experience for other customer segments, this assumption was used for all customer segments for the EBAU scenario.

The assumptions for the opt-out enrollment strategy underlying the AP scenario are based on market research and recent experience in California. In conjunction with California's Statewide Pricing Pilot, research was conducted on the opt-out rates that might occur for residential customers that were defaulted onto a CPP rate.[58] The opt-out rates for customers depended on assumptions about the level of customer awareness of alternatives and ranged from a low of 10 percent at a low level of awareness to a high of 33 percent based on complete customer awareness of all options. The opt-out rate of 25 percent assumed here (75 percent retention) is consistent with an awareness level of 70 percent from that study. This value is also reasonably close to what was actually observed following completion of California's Southwest Power Pool, when some customers were allowed to stay on the rate after the end of the pricing pilot. Roughly 65 percent of participants remained on the critical peak pricing tariff one year after the end of the Southwest Power Pool even though the participation incentive provided as part of the experiment was discontinued and customers had to start paying a monthly meter charge of between $3 and $5 depending on the utility serving them.[59]

The retention/opt-out rate for small commercial and industrial customers was assumed to be the same as for residential customers. For medium and large commercial and industrial customers, a retention rate of 60 percent was assumed. This assumption is based in part on recent analysis of the opt-out rate experienced by San Diego Gas & Electric Co., which placed all of its commercial and industrial customers that had interval meters on default CPP/TOU rates in 2008.[60] This study found that 75 percent of all customers placed on the rate stayed on the rate after the initial opt-out period had passed. However, this may not represent the long term retention rate since customers were offered first-year bill protection as part of the transition strategy for the rate. How many customers might leave at the end of that period, which occurs in late 2009, is currently unknown. Thus, a lower retention rate seemed prudent. Another relevant data point for this assumption is the experience of large commercial and industrial customers in New York who were placed on an RTP rate several years ago. Roughly 66 percent of customers stayed on this rate. Based on these two data points, an assumption of 60 percent retention seemed reasonable.

Customers are assumed not to be offered enabling technologies in the EBAU scenario, as the focus of this scenario is on non-pricing demand response programs. In the AP scenario, 95 percent of all eligible customers are offered enabling technology (in states where it is cost-effective to do so), reflecting the assumption that some states or utilities would choose not to pursue enabling technology. Sixty percent of customers accept the technology in this scenario, which is another illustrative assumption designed for the purposes of defining the scenario and reflecting that only a subset of customers will make the decision to

[57] Stephen S. George and Josh Bode. (Freeman, Sullivan & Co.). *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate™ Tariff.* Prepared for Pacific Gas and Electric Co. December 31, 2008.

[58] Momentum Market Intelligence. Customer Preferences Market Research: A Market Assessment of Time Differentiated Rates Among Residential Customers in California. December 2003.

[59] Dean Schultz and David Lineweber, *Real Mass Market Customers React to Real Time-Differentiated Rates: What Choices Do They Make and Why?* 16th National Energy Services Conference. San Diego, CA. February 2006.

[60] Steven D. Braithwait, Daniel G. Hansen, Jess Reaser and Michael P. Welsh (Christensen Associates Energy Consulting, LLC) and Stephen S. George and Josh Bode (Freeman, Sullivan & Co.) *2008 Load Impact Evaluation of California Statewide Critical Peak Pricing (CPP) for Non-Residential Customers Ex Post and Ex Ante Report* (May 1, 2009)

install enabling technologies even if they are cost-effective. In the FP scenario, all customers are offered enabling technology where it is cost effective and it is assumed that all of the customers accept the technology. Given the limited basis for setting participation rates, readers may wish to carry out some type of uncertainty analysis on these assumptions.

Per-customer impacts from non-pricing programs are provided in Table 7. These specify the amount by which an average customer participating in a given demand response program would reduce its peak demand. In Table 7, the per-customer impact is represented as a percent of the average customer's peak demand.[61] These values are based on the range of reported impacts from existing programs. For states without an existing interruptible tariff or Other DR program, or with lower-than average impacts in these programs, the average per-customer impact was used. For states without an existing interruptible tariff or Other DR program, the average per-customer impact was used. For states without existing DLC impacts a 50 percent air-conditioning cycling strategy was assumed.

Table 7: Per-Customer Impacts for Non-Pricing Programs

	Residential	Small C&I	Medium C&I	Large C&I
Direct Load Control	19% to 52%	7% to 17%	2% to 5%	N/A
Interruptible Tariffs	N/A	N/A	27% to 100%	13% to 100%
Other DR	N/A	N/A	39% to 100%	10% to 100%

Per-customer impacts from pricing programs are presented in Table 8. The range of residential impacts is a function of both the central air conditioning saturation in the state as well as the regional price elasticity.[62] Pricing impacts were simulated using the results of recent dynamic pricing experiments and studies as described earlier in this chapter and in Appendix D.

Table 8: Assumed Per-Customer Impacts from Pricing Programs

	Without Technology	With Technology
Residential	7% to 18%	21% to 34%
Small C&I	1%	15%
Medium C&I	9%	14%
Large C&I	7%	14%

Cost-Effectiveness Analysis

For the purposes of economic screening, the five demand response programs being considered in the analysis can be divided into two broad categories – those that do not require an enabling technology for participation (e.g. dynamic pricing such as critical peak pricing, peak time rebate, real-time pricing) and those that do (e.g. dynamic pricing equipped with devices that automate or reduce consumption). The demand response options that do not require an enabling technology for participation were deemed to be cost-effective for all states. For the demand response options that do require an enabling technology for participation, an economic screen was conducted to assess their cost-effectiveness in each state. The two types of options for which an economic screen was conducted are: 1) Dynamic Pricing with Enabling Technology, and 2) Direct Load Control.

The economic screen uses a simple version of the Total Resource Cost (TRC) Test that compares the lifetime benefits of the demand response option (i.e., avoided capacity costs) relative to the associated costs to enable each option (i.e., costs related to technology adoption, program implementation and

[61] However, in modeling the demand response potential, nominal impact values are used for DLC programs.
[62] CAC saturation is the percent of customers with central air conditioning.

delivery, etc.). Inputs for the economic screen include impact estimates per participant by state, capacity costs, equipment costs per participant, implementation costs, and economic parameters such as discount and cost escalation rates. The benefits are obtained by multiplying the unit demand reduction for each technology by avoided capacity costs over the ten year time horizon and discounting the dollar savings to a present value equivalent basis. For this type of preliminary analysis, the effects of incentives and participation rates are ignored. If the benefit-cost ratio is greater or equal than 1.00, the demand response option is considered cost-effective and is included in the state's full participation potential results.

The economic screening results show that Dynamic Pricing with Enabling Technology is a cost-effective option for the majority of states. However, there are a number of states for which it fails the economic screen. The results vary by customer type. Dynamic Pricing with Enabling Technology for residential customers is cost-effective for 42 states (84% of states). The option for small C&I customers is cost-effective for 40 states (80% of states) as well as for the District of Columbia. For the medium C&I customers, the option is cost-effective for 43 states (86% of states) and the District of Columbia, while for the large C&I category it is cost-effective for 45 states (90% of states) and the District of Columbia. The results indicate that Dynamic Pricing with Enabling Technology is cost-effective primarily for those states with high critical peak loads associated with large cooling or other end-use requirements. In particular, this option is highly cost-effective in Arizona and Nevada.

A few observations are worth noting for the results of the Dynamic Pricing with Enabling Technology screen:

- Because a state does not pass the cost-effectiveness screen, it does not suggest these programs should not be pursued in that state. The estimates are based on price response using class-average load shapes. Many of the states that did not pass in fact have varying weather characteristics that would lead to different impacts. Some regions might have higher impacts and thus these programs may indeed be cost-effective.
- As the customer class size increases and approaches the large C&I class (starting with the small C&I), more states become cost-effective.
- These trends suggest that as dynamic pricing tariffs are introduced across the country, utilities that are considering adopting one of their own might consider starting with the larger customer classes and gradually introduce the tariffs to the smaller classes once more information is available.
- Careful attention should be given to the economic analysis for these types of programs, particularly when looking at the residential class, which in some regions of the country may not provide the needed level of savings to justify the cost of enablement technologies such as programmable communicating thermostats and automated demand response.

Direct Load Control is a cost-effective demand response option for most states because of the higher per participant savings associated with this option. The analysis showed that Direct Load Control is cost-effective for residential customers in 48 states (96%) and the District of Columbia. The only states for which it is not cost-effective for residential customers are Alaska and Hawaii. Among both small and medium C&I customers, Direct Load Control is cost-effective for all states and the District of Columbia.
A few observations are worth noting for the results of the Direct Load Control with Enabling Technology screen:

- Most states passed the economic screen. However, for those states that failed the screen, methods of direct load control other than air conditioning might be viable.
- Methods to control water heating and pumping loads may be more viable in these regions.

For more details on the cost effectiveness analysis as well as state-level benefit-cost ratios, see Appendix D.

CHAPTER VI. BARRIERS TO DEMAND RESPONSE

A number of barriers are preventing demand response from reaching the full potential identified through this study. Some of these barriers are regulatory in nature, stemming from existing policies and practices that are not designed to facilitate the use of demand response as a resource. These barriers exist in both wholesale and retail markets. Other barriers are economic in nature. Certain technological limitations are also standing in the way. In total, 24 unique barriers to demand response have been identified through this study. Consistent with the requirements of EISA 2007, this chapter briefly summarizes these barriers to demand response. Further detail on the barriers is provided in Appendix C.

The Barriers to Demand Response

The barriers to demand response fall into four major categories: regulatory barriers, economic barriers, technical barriers, and other barriers.

- Regulatory: Regulatory barriers are caused by a particular regulatory regime, market design, market rule, or the demand response program itself. They can be divided into three sub-categories: general, wholesale-level, and retail-level.
- Economic: Economic barriers refer to situations where the financial incentive for utilities or aggregators to offer demand response programs, and for customers to pursue these programs, is limited.
- Technological: Potential technological barriers to implementation of demand response include the need for new types of metering equipment, metering standards, or communications technology.
- Other: Some additional barriers do not fall into the categories described above. These are generally related to customer perceptions of demand response programs and a willingness to enroll.

An extensive survey of the existing literature led to the identification of the 24 barriers to demand response identified in Table 9. Detailed descriptions of the barriers are provided in Appendix C.

Table 9: The Barriers to Demand Response

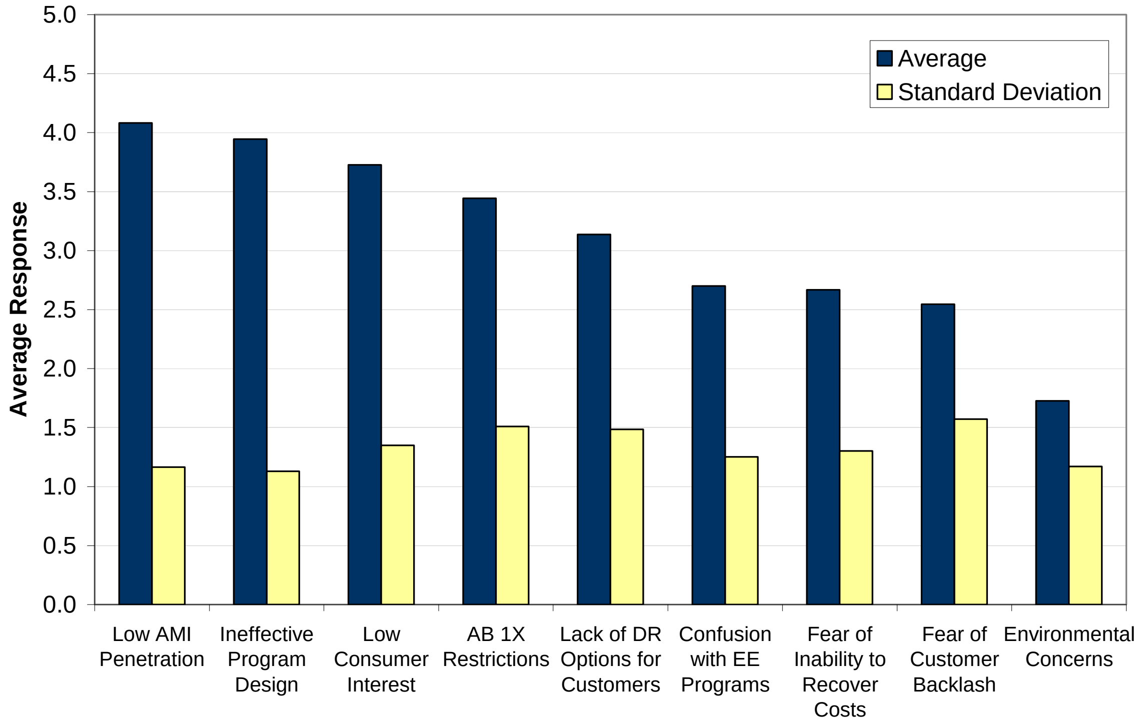
Type	Barrier
Regulatory (General)	1. Retail-wholesale disconnect (lack of dynamic pricing) 2. M&V challenges 3. Shared State and Federal Jurisdiction 4. Perception of gaming 5. Lack of real-time info sharing (ISOs and utilities) 6. Lack of reliability/predictability in demand response
Regulatory (Retail)	7. Policy restrictions on demand response 8. Ineffective demand response program design 9. Financial disincentives for utilities 10. Disagreement on cost-effectiveness analysis 11. Lack of retail competition
Regulatory (Wholesale)	12. Market structures oriented toward accommodating supply side resources
Economic	13. Inaccurate price signals 14. Lack of sufficient financial incentives to induce participation
Technological	15. Lack of AMI 16. Lack of cost-effective enabling technologies 17. Concerns about technological obsolescence and cost recovery 18. Lack of interoperability and open standards
Other	19. Lack of customer awareness and education 20. Risk aversion 21. Fear of customer backlash 22. Perceived lack of ability to respond 23. Concern over environmental impacts 24. Perceived temporary nature of demand response impacts

Assessing the Barriers

A review of the existing literature has identified a study in which many of the barriers to demand response were ranked in terms of their level of overall significance to impeding further market penetration of demand response programs. The study was conducted by The Brattle Group through a recent project with the California Energy Commission.[63] Stakeholders were interviewed, asked to identify barriers to demand response, and asked to rate the significance of the barriers on a scale from one to five, with one being "highly insignificant" and five being "highly significant." The results of the respondents' ratings are summarized in Figure 25 below.

[63] Ahmad Faruqui and Ryan Hledik, "The State of Demand Response in California," prepared for the California Energy Commission, April 2007.

Figure 25: Significance of Barriers to Demand Response in California as Identified by Stakeholders



Low AMI penetration topped the Brattle list of today's barriers to demand response. The second and third most significant barriers, both with average scores above 3.5, were ineffective program design and low consumer interest. It is interesting to note that these two barriers are probably highly correlated, as a more effective program design would be likely to encourage customer interest in demand response programs. Environmental concerns associated with demand response were deemed to be the least significant barrier.

CHAPTER VII. POLICY RECOMMENDATIONS

This chapter provides policy recommendations that, if implemented, could serve to remove the most significant barriers to achieving the demand response potential estimated in this report. At the outset, it is important to note that many of the opportunities to increase demand response potential lie at the retail level. The States and local governments will need to play a central role in promoting demand response programs needed to reach the full potential. The expansion of demand response programs will involve technologies that affect the electricity system across State and Federal jurisdictions. Some decisions may be made at the Federal level, while others will need to be made by State and local regulators or legislatures.

Statutory Requirement

EISA 2007 requires that, in addition to estimating nationwide demand response potential, FERC must include "specific policy recommendations that if implemented can achieve the estimated potential."[64] EISA 2007 states, "[s]uch recommendations shall include options for funding and/or incentives for the development of demand response resources."[65] EISA 2007 also directs FERC to note any barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available, and shall provide recommendations for overcoming these barriers.[66] Through the recommendations provided below, this chapter is responsive to all three Congressional directives.

The preceding chapters of this report analyze three scenarios under which demand response potential could increase beyond the base case level of currently planned growth in demand response programs reflected by the Business-as-Usual scenario. These are the Expanded Business-as-Usual scenario, the Achievable Participation scenario, and the Full Participation scenario. Nationally, each is estimated to produce a significant increase in demand response potential relative to the Business-as-Usual scenario. However, as detailed in Chapter III, the estimated effect of each scenario in any particular state differs depending on a range of factors in that state, such as the level of central air conditioning saturation, the price of electricity, the generation capacity level, and the existing level of demand response, including whether the state has access to spot electricity and capacity markets with demand response programs.

Thus, how much and how best to increase demand response may differ from state to state. Further, given that each scenario is based on different approaches to increasing demand response, the critical barriers confronting each of these scenarios may differ. A more complete discussion of these barriers is found in Chapter VI and Appendix C.

General Recommendations to Overcome Barriers to Achieving Demand Response Potential

Several of the barriers identified in Chapter VI significantly impede the ability to implement the estimates of demand response potential identified in this report. These barriers are highlighted below, along with recommendations for overcoming those barriers.

[64] EISA 2007, sec. 529(a).
[65] *Ibid.*
[66] *Ibid.*

Sharing of Information on Effective Program Design

As noted in Chapter VI, improved program design represents one of the most significant means for improving the market penetration of demand response programs. To ensure the maximum impact for demand response programs, regulatory authorities and industry stakeholders should have access to tools and information to assist them in establishing programs that respond to their particular situation. Such assistance could include, for example, case studies on regulatory provisions, model state laws and retail tariffs, conferences and regional workshops, and technical papers on program implementation. In particular, many large customers complain that the wide variation in demand response programs offered by RTOs and by individual utilities increases their costs to monitor demand response programs, reducing the incentive to participate. Sharing demand response program alternatives across states or regions would encourage participation by large multi-state customers.

Increasing Customer Awareness of and Education on Demand Response

Achieving higher participation in demand response programs would require greater efforts by governments (federal, state and local), electric utilities and demand response providers to educate customers about the benefits, availability and operation of programs. Many consumers are unfamiliar with the benefits of demand response and may be averse to the perceived burdens of participation or risks in demand response programs.[67] Research shows, however, that customers who experience time varying rates have high levels of satisfaction and that, when offered the option of staying on such rates, most will do so and even recommend such rate programs to their friends.[68] Therefore, any plan to expand and increase participation in any type of demand response program should be accompanied by a plan to promote customer awareness and conduct targeted consumer education. This plan would raise awareness of the concept of demand response and educate consumers about the benefits of demand response, including an increased ability to control consumption, lower electric bills and possible environmental improvements. Strategies to build consumer acceptance could include marketing campaigns, customer outreach, coordination with the Environmental Protection Agency's Energy Star program on energy efficiency, development of cost effectiveness tools and implementation of a web-based clearinghouse of demand response information. Budgets for prudently deployed education and marketing efforts would need to be fully funded, and would likely be higher under the Achievable Participation and Full Participation scenarios given the estimated expansion of dynamic pricing to include most ratepayers in the former scenario and all ratepayers in the latter scenario.

Coordination of Wholesale and Retail Demand Response Strategy

In order for any demand response strategy to be effective, programs at the wholesale and retail level should be coordinated so that wholesale and retail market designs are complementary. For example, changes to RTO or ISO market rules could create opportunities for retail demand response. Industry and regulators should develop a comprehensive strategy for demand response that, mindful of respective jurisdictions, includes RTO market design changes necessary to accommodate retail demand response programs and retail tariff and pricing changes that are consistent with wholesale market designs.

Interoperability and Open Standards

Advanced metering infrastructure (AMI) will be encouraged by improving and expanding interoperability, open standards for communications protocols and meter data reporting standards. Development of these standards would allow the flow of information that is currently impeded by the existence of multiple, competing state and local requirements. Interoperability also would enable the development of new technologies, such as smart appliances, to support broader application of demand

[67] See discussion in Appendix C, p. 218.
[68] *Ibid*, p. 219.

response programs and dynamic pricing. Congress recognized the need for such standards in EISA 2007, granting the FERC authority to approve standards developed through the NIST consensus process. Regulators and industry participants should continue to support the development of adequate standards through the ongoing NIST process.

Coordination of Demand Response and Energy Efficiency Policies

Policies on demand response and energy efficiency should be coordinated, as appropriate. Demand response actions and energy efficiency investments are linked. Customer involvement in demand response activities typically leads to increased attention to electricity consumption and heightened interest in energy efficiency. In order to ensure that demand response and energy efficiency policies do not work at cross purposes, these policy initiatives should be coordinated. State energy master plans like those developed by Maryland, Michigan, and New Jersey represent a good example of explicit incorporation and linkage of demand response and energy efficiency goals and policies. Major initiatives such as the National Action Plan for Energy Efficiency and the National Action Plan on Demand Response should be closely coordinated.

Role of Demand Response in Operational and Long-Term Planning, and Recovery of Associated Costs

Demand response resources can play an important role in operational and long-term planning. Incorporating demand response resources into planning horizons and load forecasts allows transmission providers and load-serving entities to depict more accurately the energy needs of their areas, thereby potentially deferring or offsetting costly investments in new peaking generation and transmission. Demand response resources can also provide an important role in real-time operations, including providing emergency response and ancillary services. The Commission has recognized the value of demand response resources in long-term and operational planning in several key recent orders. Order No. 890 required transmission providers to establish a coordinated, open planning process that allows for the incorporation of demand response resources in all phases of the planning process on a basis comparable to other resources.[69] Order Nos. 693 and 719 recognized the ability of demand response resources to provide certain ancillary services when technically feasible.[70] Further integration of demand response will depend on a clear articulation by regulators and legislators of the expected role of demand response into operational and long-term planning. Key issues that should be resolved include how to account for and plan for customer electricity consumption changes in response to dynamic pricing, the ability of demand response resources to provide sustainable, long-term resources consistent with reliability requirements, appropriate compensation of demand response resources, and proper treatement of costs related to incorporation of demand response resources.

Recommendations to Achieve Specific Demand Response Potential Scenarios

Below are recommendations tailored to each scenario, consistent with the requirement to estimate how much of the potential can be achieved within five and ten years, accompanied by specific policy recommendations to achieve the potential.

Expanded Business-as-Usual Scenario

[69] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[70] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007) and Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 61,400 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), reh'g pending.

The increase in demand response estimated under the Expanded Business-as-Usual scenario is based on an assumption that current best-practice demand response programs are expanded to all states. To implement such an expansion of demand response activities, it would be necessary to increase significantly the number and extent of direct load control programs and interruptible tariffs, particularly in regions and states that currently lack programs. A means of broadly sharing information on the development, implementation and evaluation of direct load control programs and interruptible tariffs would be helpful to states and localities considering similar programs. Development and updating of model cost-effectiveness tools, particularly to include environmental challenges facing the states and the nation, and to reflect the existence of spot wholesale and capacity markets in many regions, would also be useful.

The Expanded Business-as-Usual scenario also assumes at least some amount of participation in dynamic pricing at the retail level. In particular, all currently planned and announced AMI deployments would need to be approved and installed to achieve the estimated demand response potential. This would require broad-based support from utilities, governors, legislatures and state and local regulators. In addition, funding issues would need to be addressed in order to consider the rate impact and benefits associated with AMI for all customers.

There are two additional recommendations for actions that could significantly expand the demand response programs necessary to achieve the potential represented by the Extended Business-as-Usual scenario. First, in order to encourage more aggressive participation in expanded direct load control programs and use of interruptible tariffs, payments to demand response resources should be designed to compensate them for the value they provide. Some direct load control programs and interruptible tariffs may not provide a sufficient financial incentive to participate. From an operational planning perspective, reliable and cost-effective demand response is valuable whether it is used or not, because it serves as an available resource that can be called upon during low probability events, such as system emergencies. Regulators and industry should examine compensation methods to assure that demand response is appropriately compensated.

Second, development of standardized practices for quantifying demand reductions would greatly improve the ability of system operators to rely on demand response programs of all kinds and would minimize gaming opportunities. For example, payments under direct load control programs and interruptible tariffs are dependent on estimates of demand reductions. The lack of standards for measuring and verifying reductions in demand has made it difficult to plan reliably for these resources, and has fueled concern about potential gaming by participants. Central to the issue of measurement is a determination of the customer baseline, or the estimate of what metered load would have been without the reduction in demand. The North American Energy Standards Board (NAESB) is in the process of developing business practice standards for measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets. Upon completion, federal and state regulators should work with RTOs and utilities to incorporate these standards into their processes for settlement, operations and long-term planning. In addition, efforts by states such as California to develop protocols for estimating demand reduction should be encouraged and possibly adopted by other states.

Achievable Participation and Full Participation Scenarios

The increase in demand response participation estimated under the Achievable Participation and Full Participation scenarios is primarily driven by widespread implementation of dynamic pricing. Universal deployment of AMI is assumed in every state, along with implementation of cost-effective enabling technologies for those customers participating in a dynamic pricing program. Examples of enabling technologies include in-home displays, programmable communicating thermostats, or home area networks. In order to achieve the demand response potential estimated in these scenarios, it would be necessary for utilities to adopt and implement AMI. AMI has benefits to utilities beyond the facilitation of dynamic pricing; for example it can substantially reduce the cost to read meters. Moreover, all funding-related issues associated with AMI deployment would need to be addressed. In addition to directly funding AMI and implementing technologies, tax credits or accelerated depreciation could be offered for investments.

The Achievable Participation scenario assumes universal adoption of default tariffs that impose dynamic pricing on customers unless they expressly choose not to participate in the program. The Full Participation scenario assumes mandatory participation in dynamic pricing programs by all customers. To achieve the estimated demand response potential under either scenario, it would be necessary for retail regulators to modify existing electric utility rates and rate structures to implement dynamic pricing on a default or mandatory basis. Such rates would need to be designed to ensure that dynamic prices provide for adequate recovery of investments, while also offering time-varying electricity prices to customers. Funding for, or incentives to participate in, default dynamic pricing programs could be addressed by national energy policy leaders, the electric industry, consumer organizations, governors, state legislatures, and local and retail regulators. This is especially important as all these entities consider demand response programs in the context of climate change and renewable portfolio requirements.

A significant additional barrier exists for implementation of dynamic pricing under the Achievable Participation or Full Participation scenarios. This report notes that dynamic pricing with enabling technologies is not cost-effective for all customers in all states. For example, in cooler states without a large presence of central air conditioning, implementation of dynamic pricing with enabling technology for residential customers may not be cost-effective. While the cost of some technologies, such as programmable communicating thermostats, has declined (they are less than one-third of the price three years ago), government funding may be appropriate to expedite the development and deployment of other innovations, such as AMI and related technologies.

To support these scenarios, the customer education and technical assistance recommended above should be expanded and enhanced. Many customers, particularly residential customers, will need extensive help understanding the advantages of AMI and dynamic pricing. Sufficient resources should be expended under both the Achievable and Full Participation Scenarios to ensure that customers are comfortable with the new technology and are capable of adjusting their usage patterns and investment decisions. Similarly, better and more current information on AMI technology, costs, operational, market, and consumer benefits should be shared with regulators to support their decision-making on the full deployment of AMI and dynamic pricing.

National Action Plan on Demand Response

In addition to developing a national estimate of demand response that is documented in this report, EISA 2007 requires FERC to develop a National Action Plan within one year of submission of this report. EISA 2007 provides that the National Action Plan will, in the context of supporting demand response, develop: (1) a national, customer-based communications program; (2) a technical assistance strategy to states; and (3) a set of tools, information and support materials for use by stakeholders. The Action Plan will be guided in part by the results of this Assessment.

REFERENCES

American Council for an Energy-Efficient Economy. "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs by ACEEE," March 2007.

Barakat & Chamberlin, Inc., "Impact of Demand-Side Management on Future Customer Electricity Demand: An Update," prepared for EEI and EPRI, June 1992.

Braithwait, Steven D., Daniel G. Hansen, Jess Reaser and Michael P. Welsh (Christensen Associates Energy Consulting, LLC) and Stephen S. George and Josh Bode (Freeman, Sullivan & Co.) **2008 Load Impact Evaluation of California Statewide Critical Peak Pricing (CPP) for Non-Residential Customers Ex Post and Ex Ante Report** (May 1, 2009)

California Energy Commission, 2007 Integrated Energy Policy Report, CEC-100-2007-008 CMF.

Competition ANOPR, FERC Stats. & Regs.¶ 32,617, p. 68-74.

CPUC Decision 04-04-020.

CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

Demand Response Research Center, "Automated Demand Response for Commercial and Industrial Facilities: A Progress Report to the CPUC," December 2007.

Draft Agenda to NAESB DSM-EE meeting on October 3, 2008.

Decision adopting dynamic pricing timetable and rate design guidance for Pacific Gas & Electric Company, D. 08-07-045, July 31, 2008.

Earle, Robert and Ahmad Faruqui, "Demand Response and the Role of Regional Transmission Operators," prepared for EPRI, December 2006.

Elliott, R. Neal, et al, "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs," March 2007.

Energetics Incorporated, "Proceedings to PJM Symposium on Demand Response," June 8, 2007.

Faruqui, Ph.D., Ahmad and Lisa Wood, Ph.D., "Quantifying the Benefits of Dynamic Pricing in Mass Markets," prepared for the Edison Electric Institute by The Brattle Group, January 2008.

Faruqui, Ahmad and Ryan Hledik. "The State of Demand Response in California," prepared for the California Energy Commission, April 2007.

Faruqui, Ahmad and Ryan Hledik. "California's Next Generation of Load Management Standards," prepared for the California Energy Commission, May 2007.

Faruqui, Ahmad, Ryan Hledik, Hannes Pfeifenberger, and Sam Newell, "The Power of Five Percent," The Electricity Journal, October 2007.

Ahmad Faruqui, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," **The Electricity Journal**, April 2009.

Faruqui, Ahmad and Sanem Sergici, "Household response to dynamic pricing of electricity: A survey of the experimental evidence," January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

Faruqui, Ahmad and Stephen S. George, "Demise of PSE's TOU Program Imparts Lessons," Electric Light and Power, January 2003.

FERC Staff, "2006 Assessment of Demand Response and Advanced Metering," August 2006.

FERC Staff, "2007 Assessment of Demand Response and Advanced Metering," September 2007.

FERC Staff, "2008 Assessment of Demand Response and Advanced Metering," December 2008.

George, Stephen S., and Ahmad Faruqui, Impact **Evaluation of the California Statewide Pricing Pilot, Final Report.** March 16, 2005

George, Stephen S., Ahmad Faruqui and John Winfield. **California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update**. Final Report, June 28, 2006.

George, Stephen S., Josh Bode and Josh Schellenberg, **Load Impact Estimates for Southern California Edison's Demand Response Program Portfolio**, September 25, 2008.

George, Stephen S., and Josh Bode, 2008 **Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRateTM Tariff**. Prepared for Pacific Gas and Electric Co. December 31, 2008.

Goldman, Charles, et al, "Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study," Lawrence Berkeley National Laboratory, January 2007.

Heschong Mahone Group, Inc., "California Demand Response Potential Study – Phase 1 (Draft)," for San Diego Gas & Electric, July 7, 2007.

International Energy Agency. Roadmap for Demand Response in the Australian National Electricity Market. December 2006. Page 30.

KEMA, "Overcoming Barriers to Customer Demand Response through Coordinated Retail and Wholesale Regulatory Policy," Phase I, July 20, 2008.

KEMA, "Phase I Presentation: Demand Response Study for NARUC/FERC Collaborative," July 20, 2008.

Midwest ISO Regulatory and Economic Studies, "Demand Response and the MTEP Process," March 3, 2008.

Momentum Market Intelligence, Statewide Pricing Pilot: End-of-Pilot Participant Assessment. December 2004.

Momentum Market Intelligence. **Customer Preferences Market Research: A Market Assessment of Time Differentiated Rates Among Residential Customers in California**. December 2003.

Mountain, Dean. The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot. March 2006.

NAESB comments to FERC Technical Conference on Demand Response in Wholesale Markets, April 2007.

NERC, "2008 Summer Reliability Assessment," May 2008.

NERC, "Data Collection for Demand-Side Management for Quantifying Its Influence on Reliability: Results and Recommendations," December 2007.

Newell, Sam and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

Peak Load Management Alliance. "Demand Response: Principles for Regulatory Guidance," February 2002.

Pratt, Robert. "Fully-Engaging Demand Response: the Olympic Peninsula GridWise and Grid Friendly™ Appliance Demonstrations" presentation prepared for Southern California Edison Demand Response Forum, November 2007.

Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008. Docket Number AD08-8-000.

Quantec, "Demand Response Proxy Supply Curves," for PacifiCorp, September 8, 2006.

Quantec, Summit Blue, and Nexant, Inc., "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources," for PacifiCorp, July 11, 2007.

"Rethinking Rate Design," prepared for the Demand Response Research Center, August 2007.

Schultz, Dean and David Lineweber, Real Mass Market Customers React to Real Time-Differentiated Rates: What Choices Do They Make and Why? 16th National Energy Services Conference. San Diego, CA. February 2006.

Toronto Hydro Energy Services. Development of an Electricity Demand Management and Demand Response Program for Commercial Buildings: Report on Design Charette. November 28, 2003.

United States Government Accountability Office, "Consumers Could Benefit from Demand Programs, but Challenges Remain," Report to the Chairman, Committee on Governmental Affairs, U.S. Senate, August 2004.

Wikler, G., et. al., "Enhancing Price Response through Auto-DR: California's 2007 Implementation Experience," Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, August 2008.

Winkler, Eric, Paul Wattles, and Donna Pratt, "Measurement and Verification Standards: Wholesale Electric Demand Response Recommendations Summary," presented at NAESB DSM-EE meeting, October 3, 2008.

APPENDIX A. STATE PROFILES

The following state profiles provide detailed information on the demand response potential projections for each state in the Assessment. The case studies presented in Chapter V of this report should be used as a guide for interpreting the results.

Some of the state profiles make reference to the "share of peak demand" that each sector contributes. This refers to the fraction of the entire state peak demand that is represented by that sector. In other words, if a state has peak demand of 10 GW and the residential class peak demand is 4 GW, the share of peak demand belonging to the residential class is 40 percent.

To provide context for interpreting the results, Table A-1 provides basic descriptive statistics for each of the states and the District of Columbia.

Also, in Table A-2 and Table A-3 are summaries of the potential peak reductions from demand response for 2014 (year five of the analysis horizon) and 2019 (year ten of the analysis horizon) for all states, as a fraction of the estimated summer peak demand without demand response. (In a few instances, estimated growth in peak demand between 2014 and 2019 exceeds estimated growth of demand response potential over the same period, causing the 2014 fraction to exceed the 2019 fraction)

Table A-1: Summary of Key Data by State

State	Total population	Number of accounts by rate class				System Peak Demand (MW)	Average peak load per customer (kW)				Annual average growth rate in peak (%)		CAC saturation for Residential sector (%)	AMI deployment in 2019 under EBAU scenario (%)
		Residential	Small C&I	Medium C&I	Large C&I		Residential	Small C&I	Medium C&I	Large C&I	Res	C&I		
Alabama	4,661,900	2,077,677	362,448	12,354	3,801	19,000	3.4	15.1	192	748	1.6	0.6	62	68
Alaska	686,293	266,671	45,183	3,270	62	1,417	0.9	4.5	80	1,029	0.4	0.2	3	21
Arizona	6,500,180	2,567,749	280,527	15,965	1,381	18,456	3.8	16.9	165	822	0.2	0.1	87	83
Arkansas	2,855,390	1,301,517	199,604	6,629	3,442	9,875	2.8	9.1	93	801	1.2	0.3	55	40
California	36,756,666	12,971,924	1,567,550	301,662	17,772	57,137	1.2	3.2	38	555	0.8	0.4	41	90
Colorado	4,939,456	2,068,055	282,139	88,021	1,531	10,837	1.5	1.9	40	901	0.9	0.1	47	43
Connecticut	3,501,252	1,449,983	141,998	11,261	8,044	7,524	1.6	3.9	63	206	0.9	0.4	27	52
Delaware	873,092	390,239	47,323	1,475	374	2,503	1.9	15.2	125	951	0.4	0.1	53	79
District of Columbia	591,833	206,047	24,506	1,842	1,229	2,403	1.6	9.5	158	745	1.5	0.1	56	100
Florida	18,328,340	8,615,249	921,368	224,874	9,195	49,453	3.1	2.9	40	696	0.2	0.6	91	74
Georgia	9,685,744	4,039,005	483,576	66,628	11,363	28,215	3.4	5.4	60	602	0.6	0.3	82	67
Hawaii	1,288,198	409,581	55,808	7,482	632	1,790	1.0	4.2	45	842	0.9	0.2	18	72
Idaho	1,523,816	647,581	65,923	55,692	928	4,962	2.9	3.9	31	636	0.4	0.1	67	69
Illinois	12,901,563	5,054,895	541,263	26,791	21,435	30,465	1.7	7.3	28	450	1.3	0.4	75	51
Indiana	6,376,792	2,734,788	286,888	65,468	8,038	22,890	2.4	6.3	52	798	1	0.3	74	40
Iowa	3,002,555	1,320,241	183,320	30,471	3,507	9,169	1.9	4.1	47	709	1.6	1.1	70	55
Kansas	2,802,134	1,213,189	221,809	10,962	7,594	8,630	2.8	6.4	44	318	1.3	0.5	84	29
Kentucky	4,269,245	1,918,247	272,458	27,771	3,050	18,889	3.0	10.5	176	959	1.3	0.4	76	33
Louisiana	4,410,796	1,870,160	196,805	89,052	3,192	16,332	3.5	14.6	39	771	1.6	0.4	75	40
Maine	1,316,456	693,400	75,666	13,927	1,065	2,812	0.8	2.0	30	571	0.7	0.4	14	54
Maryland	5,633,597	2,187,996	230,938	17,496	4,054	13,583	2.6	13.1	32	606	0.4	0.1	78	82
Massachusetts	6,497,967	2,631,568	367,459	22,605	4,510	12,695	1.0	6.0	24	642	0.8	0.4	13	26
Michigan	10,003,422	4,336,390	485,729	44,172	10,836	23,292	1.5	6.2	48	609	1.2	0.4	57	69
Minnesota	5,220,393	2,283,083	189,477	75,091	10,044	14,123	1.7	3.2	42	327	1.3	1.1	51	46
Mississippi	2,938,618	1,222,047	228,202	1,565	2,228	9,835	3.5	8.8	78	1,215	1.6	0.6	75	42
Missouri	5,911,605	2,670,172	347,394	25,739	4,651	17,362	3.1	5.0	110	748	1.3	0.7	88	45
Montana	967,440	456,112	103,892	890	238	2,991	1.6	12.3	157	1,101	1.3	0.2	42	22
Nebraska	1,783,432	787,312	178,123	10,854	2,889	5,771	2.6	4.5	128	291	1.6	1.1	83	19
Nevada	2,600,167	1,079,306	145,469	4,497	1,963	7,538	3.1	12.1	112	931	0.2	0.1	87	25
New Hampshire	1,315,809	600,399	102,868	831	1,875	2,539	1.1	4.7	32	306	0.2	0.4	13	45
New Jersey	8,682,661	3,414,289	461,304	10,998	10,375	17,273	2.2	7.1	77	395	0.8	0.7	55	56
New Mexico	1,984,356	829,100	122,560	16,755	1,296	4,671	1.3	4.8	61	707	1.2	0.1	42	37
New York	19,490,297	6,855,544	958,009	66,351	5,265	33,809	1.3	5.7	81	820	0.8	0.3	17	42
North Carolina	9,222,414	4,128,231	619,832	29,169	3,277	26,548	3.2	5.6	168	1,373	0.5	0.3	84	47
North Dakota	641,481	310,222	54,365	2,211	699	2,379	2.2	9.7	129	614	1.6	1.1	51	34
Ohio	11,485,910	4,908,791	569,999	59,607	13,010	33,238	2.0	8.5	65	604	1.3	0.3	63	39
Oklahoma	3,642,361	1,629,818	243,831	30,398	3,097	11,919	3.3	3.8	70	778	1.2	0.1	84	41
Oregon	3,790,060	1,610,829	220,262	36,132	1,521	10,476	1.9	4.5	75	680	0.7	0.4	38	59
Pennsylvania	12,448,279	5,217,010	618,439	75,656	10,577	31,488	1.7	8.2	43	644	1.2	0.7	50	64
Rhode Island	1,050,788	432,307	48,623	8,614	864	1,785	1.0	2.7	32	393	0.8	0.4	12	25
South Carolina	4,479,800	2,028,361	326,244	15,666	2,327	16,947	3.6	7.6	172	1,696	1	0.3	84	37
South Dakota	804,194	355,714	66,375	658	875	2,128	2.2	9.3	87	402	1.6	1.1	71	27
Tennessee	6,214,888	2,660,110	428,663	30,312	3,735	22,475	3.9	11.5	186	376	1	0.6	81	29
Texas	24,326,974	9,397,317	1,269,490	411,961	5,756	72,723	3.3	3.7	47	2,086	0.3	0.3	80	71
Utah	2,736,424	911,744	103,864	16,754	791	5,742	1.6	4.9	86	1,322	0.4	0.1	42	23
Vermont	621,270	310,842	46,230	3,075	313	1,085	0.9	2.2	49	773	0.6	0.4	7	59
Virginia	7,769,089	3,170,126	369,208	32,352	7,886	22,412	2.5	4.6	88	708	0.7	0.3	50	46
Washington	6,549,224	2,762,275	345,256	26,145	3,568	18,538	1.8	6.5	110	771	0.6	0.4	29	46
West Virginia	1,814,468	855,919	135,823	11,181	1,199	6,916	2.3	6.3	78	1,431	1.6	0.1	50	45
Wisconsin	5,627,967	2,581,840	290,192	44,419	4,518	14,845	1.4	4.1	61	782	1.5	0.9	62	65
Wyoming	532,668	245,648	61,758	3,587	585	3,236	1.7	14.9	66	1,551	1.6	0.2	42	21

Table A-2: Potential Peak Demand Reduction by State (2014)

	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	6%	10%	13%	17%
Alaska	0%	2%	2%	2%
Arizona	1%	5%	14%	22%
Arkansas	3%	13%	13%	14%
California	7%	7%	12%	16%
Colorado	4%	5%	6%	7%
Connecticut	17%	22%	23%	24%
Delaware	4%	7%	11%	15%
District of Columbia	8%	18%	18%	21%
Florida	5%	9%	13%	17%
Georgia	4%	12%	16%	19%
Hawaii	2%	5%	7%	9%
Idaho	1%	6%	11%	15%
Illinois	7%	9%	9%	9%
Indiana	5%	7%	8%	10%
Iowa	6%	9%	10%	12%
Kansas	3%	7%	8%	9%
Kentucky	2%	5%	6%	7%
Louisiana	0%	5%	6%	7%
Maine	17%	19%	20%	21%
Maryland	11%	14%	22%	28%
Massachusetts	7%	10%	11%	11%
Michigan	8%	13%	14%	15%
Minnesota	12%	13%	15%	16%
Mississippi	1%	7%	8%	9%
Missouri	1%	9%	11%	13%
Montana	0%	4%	4%	5%
Nebraska	10%	14%	14%	15%
Nevada	0%	9%	10%	12%
New Hampshire	4%	8%	8%	8%
New Jersey	4%	8%	9%	10%
New Mexico	1%	6%	6%	7%
New York	8%	9%	10%	11%
North Carolina	5%	10%	10%	11%
North Dakota	1%	5%	6%	6%
Ohio	1%	11%	12%	12%
Oklahoma	0%	9%	10%	10%
Oregon	0%	3%	6%	9%
Pennsylvania	7%	11%	14%	16%
Rhode Island	7%	10%	11%	11%
South Carolina	4%	9%	10%	11%
South Dakota	1%	6%	6%	6%
Tennessee	5%	8%	9%	9%
Texas	1%	8%	12%	16%
Utah	8%	12%	13%	14%
Vermont	8%	9%	10%	11%
Virginia	1%	6%	7%	8%
Washington	0%	4%	5%	7%
West Virginia	3%	10%	10%	11%
Wisconsin	1%	5%	6%	7%
Wyoming	0%	6%	7%	7%

Table A-3: Potential Peak Demand Reduction by State (2019)

	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	5%	10%	15%	21%
Alaska	0%	2%	5%	7%
Arizona	1%	5%	18%	28%
Arkansas	2%	13%	17%	21%
California	6%	7%	13%	17%
Colorado	3%	5%	12%	17%
Connecticut	16%	21%	26%	29%
Delaware	4%	7%	13%	19%
District of Columbia	7%	18%	17%	20%
Florida	5%	9%	18%	25%
Georgia	3%	12%	18%	25%
Hawaii	2%	5%	8%	11%
Idaho	1%	6%	14%	21%
Illinois	6%	8%	12%	15%
Indiana	5%	7%	13%	18%
Iowa	5%	8%	13%	17%
Kansas	2%	7%	13%	17%
Kentucky	1%	5%	11%	18%
Louisiana	0%	5%	12%	18%
Maine	16%	19%	22%	24%
Maryland	11%	13%	24%	32%
Massachusetts	7%	10%	14%	17%
Michigan	8%	12%	14%	16%
Minnesota	12%	13%	16%	19%
Mississippi	1%	7%	13%	19%
Missouri	1%	9%	14%	19%
Montana	0%	4%	9%	14%
Nebraska	9%	13%	19%	24%
Nevada	0%	9%	18%	26%
New Hampshire	3%	8%	10%	13%
New Jersey	4%	8%	12%	18%
New Mexico	1%	6%	11%	15%
New York	7%	9%	13%	17%
North Carolina	4%	10%	17%	25%
North Dakota	1%	5%	10%	14%
Ohio	1%	11%	14%	17%
Oklahoma	0%	9%	14%	19%
Oregon	0%	3%	9%	14%
Pennsylvania	7%	10%	15%	19%
Rhode Island	7%	10%	13%	16%
South Carolina	4%	9%	17%	23%
South Dakota	1%	6%	12%	17%
Tennessee	4%	8%	17%	24%
Texas	1%	8%	15%	21%
Utah	7%	12%	18%	23%
Vermont	7%	8%	11%	13%
Virginia	1%	6%	11%	16%
Washington	0%	4%	9%	12%
West Virginia	3%	10%	13%	18%
Wisconsin	1%	5%	8%	11%
Wyoming	0%	6%	9%	12%

Alabama State Profile

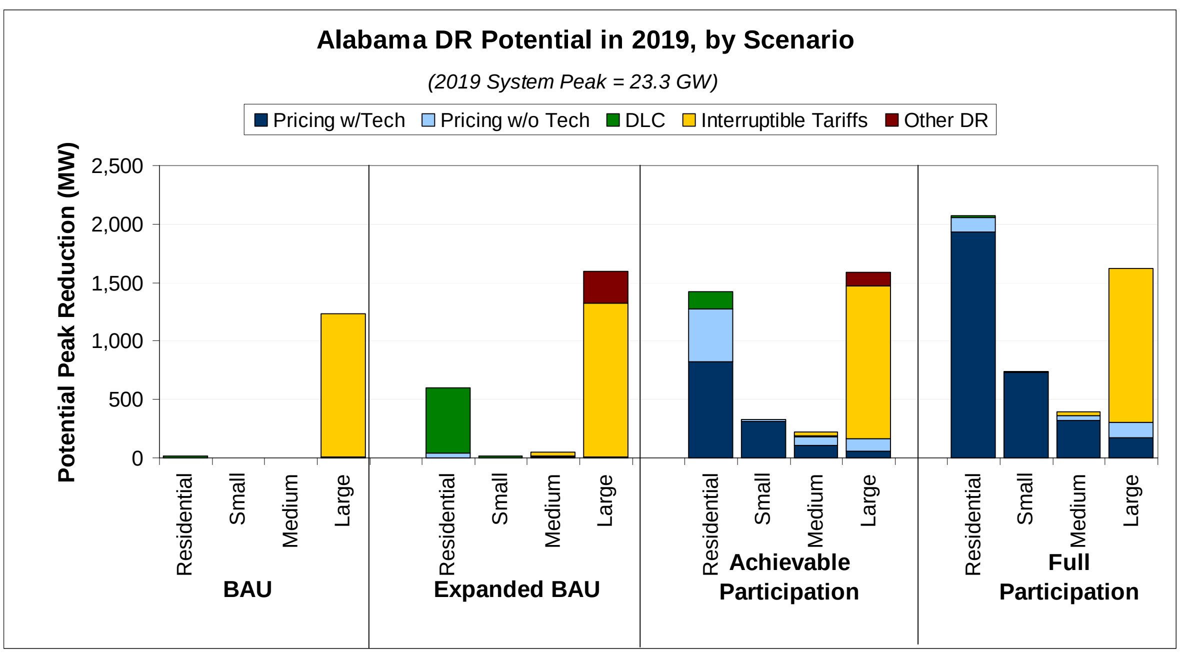
Key drivers of Alabama's demand response potential estimate include: higher-than-average residential CAC saturation of 62 percent, a customer mix that has an above average share of peak demand in the Small C&I class (31%), a moderate amount of existing Interruptible Tariffs for the Large C&I class, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. Most of the growth potential in demand response comes from the Residential class.

BAU: Alabama's existing demand response comes primarily from a large Interruptible Tariff program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through two sources. There is the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. In addition, there is a lot of growth potential for DLC in the Residential class due higher-than-average residential CAC saturation.

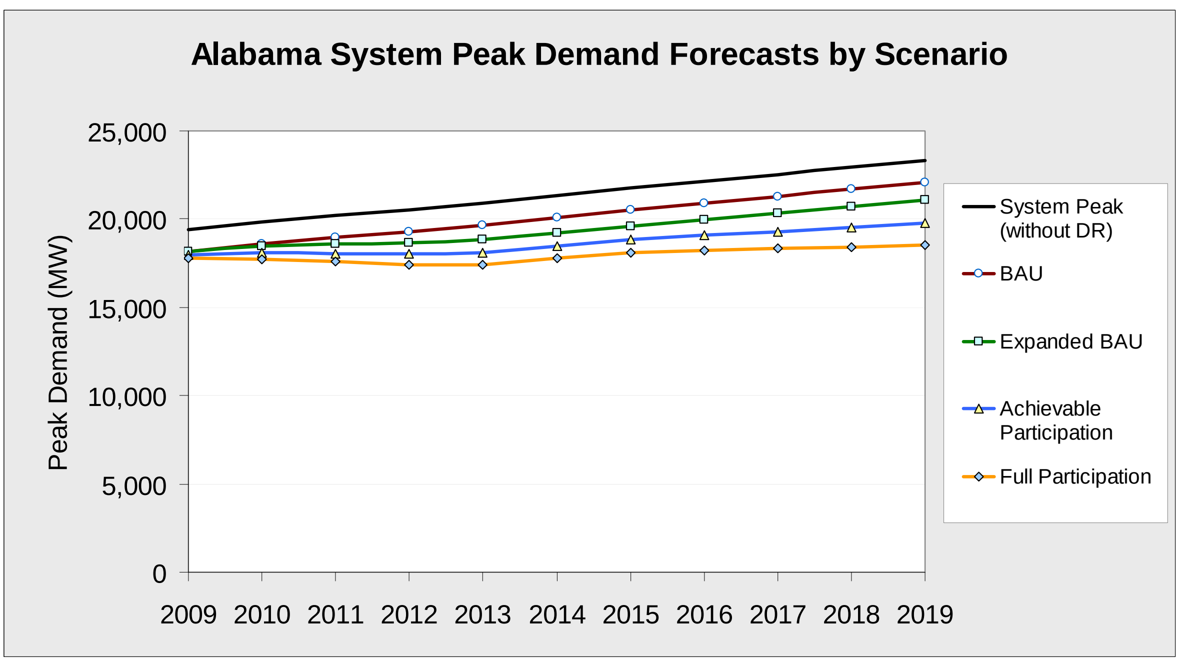
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is not significantly higher than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation in the Residential class drives the increase in impacts. The growth in impacts from the base BAU scenario are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Alabama, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	10	0.0%	10	0.0%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	1,224	5.2%	1,224	5.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	16	0.1%	0	0.0%	0	0.0%	1,234	5.3%	1,250	5.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	42	0.2%	1	0.0%	8	0.0%	10	0.0%	61	0.3%
Automated/Direct Load Control	559	2.4%	13	0.1%	9	0.0%	0	0.0%	581	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	601	2.6%	15	0.1%	50	0.2%	1,592	6.8%	2,258	9.7%
Achievable Participation										
Pricing with Technology	825	3.5%	312	1.3%	110	0.5%	58	0.2%	1,305	5.6%
Pricing without Technology	453	1.9%	17	0.1%	73	0.3%	105	0.5%	648	2.8%
Automated/Direct Load Control	145	0.6%	3	0.0%	4	0.0%	0	0.0%	152	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	1,422	6.1%	333	1.4%	221	0.9%	1,586	6.8%	3,562	15.3%
Full Participation										
Pricing with Technology	1,929	8.3%	730	3.1%	322	1.4%	169	0.7%	3,150	13.5%
Pricing without Technology	130	0.6%	9	0.0%	36	0.2%	136	0.6%	310	1.3%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,074	8.9%	739	3.2%	391	1.7%	1,616	6.9%	4,821	20.6%



Alaska State Profile

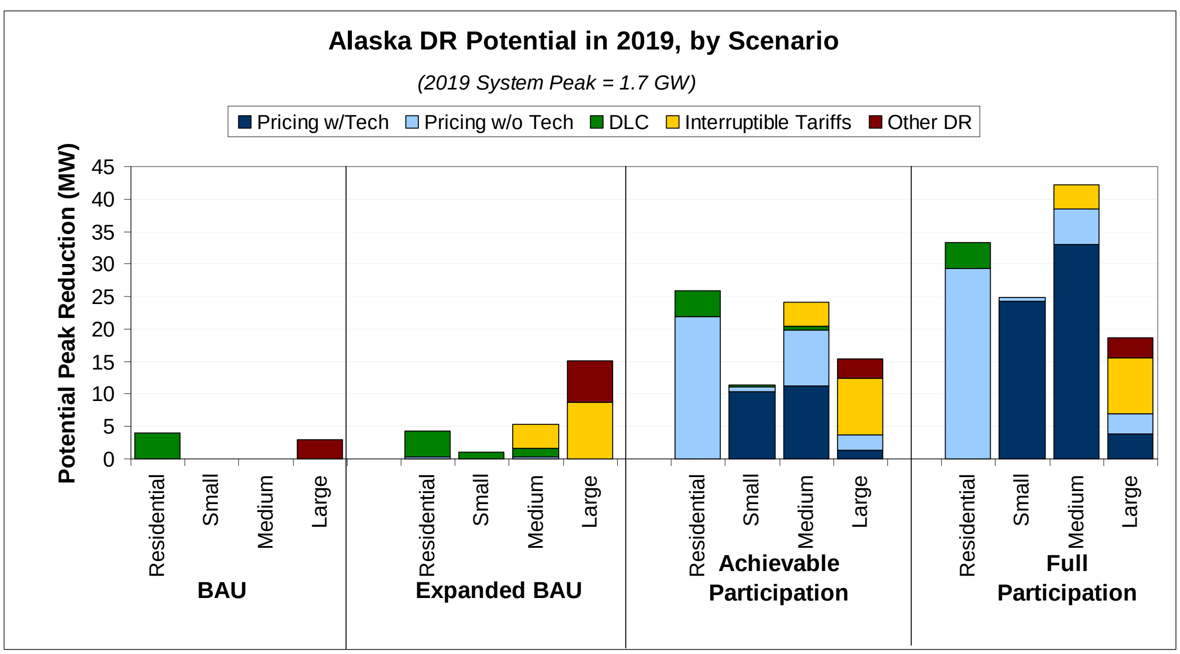
Key drivers of Alaska's demand response potential estimate include: very low residential CAC saturation, a customer mix that has an above average share of peak demand in the Small and Medium C&I classes (26% and 34%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a lower-than-average rate. Enabling technologies are cost effective for all C&I classes in the state, but not for the residential class.

BAU: Alaska's existing demand response comes from two sources. In the Residential class, there is a small amount of non-air conditioning DLC, and in the Medium C&I class, there is a small amount of Other DR.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs programs for the Large C&I class, which currently do not exist in the state. Within the Large C&I class, demand response is split between Interruptible Tariffs and Other DR. The only other substantial growth in demand response comes from Interruptible Tariffs in the Medium C&I class.

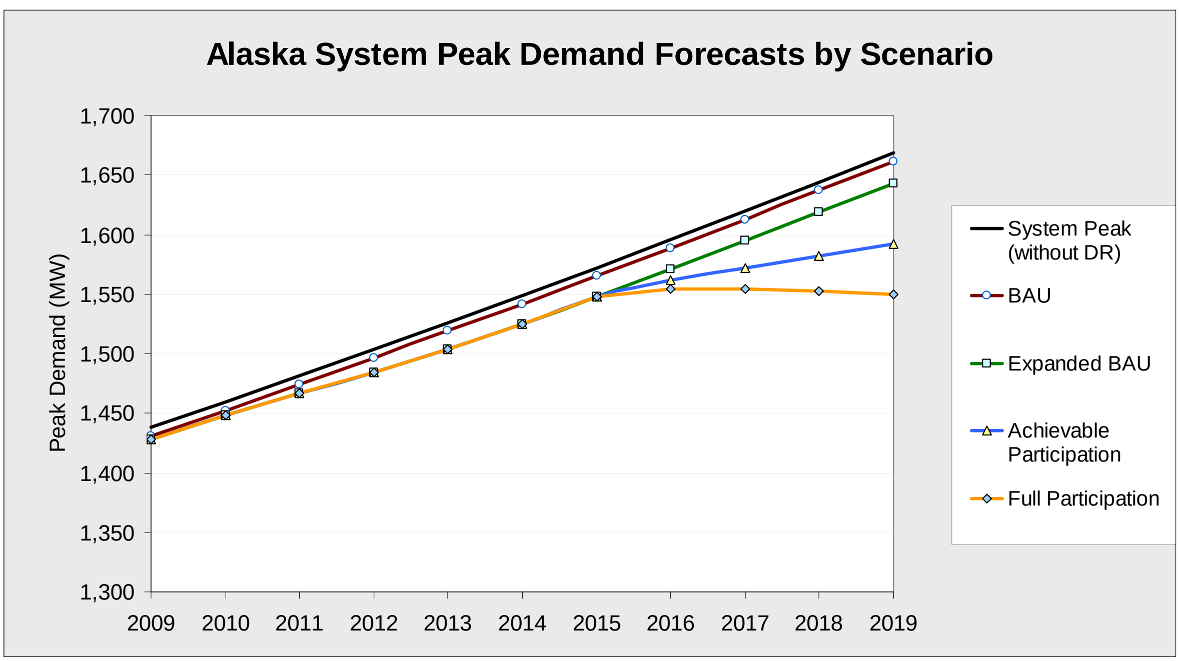
Achievable Participation: A significant increase in demand response potential comes from dynamic pricing with and without enabling technology. However, for the Large C&I class specifically, demand response potential does not change significantly from Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. Since enabling technology did not prove to be cost-effective in the Residential sector, all of the pricing impacts are without enabling technology.

Full Participation: Similar to the Achievable Participation scenario, a significant increase in demand response potential comes from dynamic pricing. The majority of the statewide impacts come from pricing with enabling technologies, which are cost-effective for all customer classes except Residential.



Total Potential Peak Reduction from Demand Response in Alaska, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	4	0.2%	0	0.0%	0	0.0%	3	0.2%	7	0.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	4	0.2%	1	0.1%	1	0.1%	0	0.0%	6	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	6	0.4%	6	0.4%
Total	4	0.3%	1	0.1%	5	0.3%	15	0.9%	26	1.5%
Achievable Participation										
Pricing with Technology	0	0.0%	10	0.6%	11	0.7%	1	0.1%	23	1.4%
Pricing without Technology	22	1.3%	1	0.0%	9	0.5%	2	0.1%	34	2.0%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.0%	0	0.0%	5	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	26	1.6%	11	0.7%	24	1.4%	15	0.9%	77	4.6%
Full Participation										
Pricing with Technology	0	0.0%	24	1.5%	33	2.0%	4	0.2%	61	3.7%
Pricing without Technology	29	1.8%	0	0.0%	5	0.3%	3	0.2%	38	2.3%
Automated/Direct Load Control	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	33	2.0%	25	1.5%	42	2.5%	19	1.1%	119	7.1%



Arizona State Profile

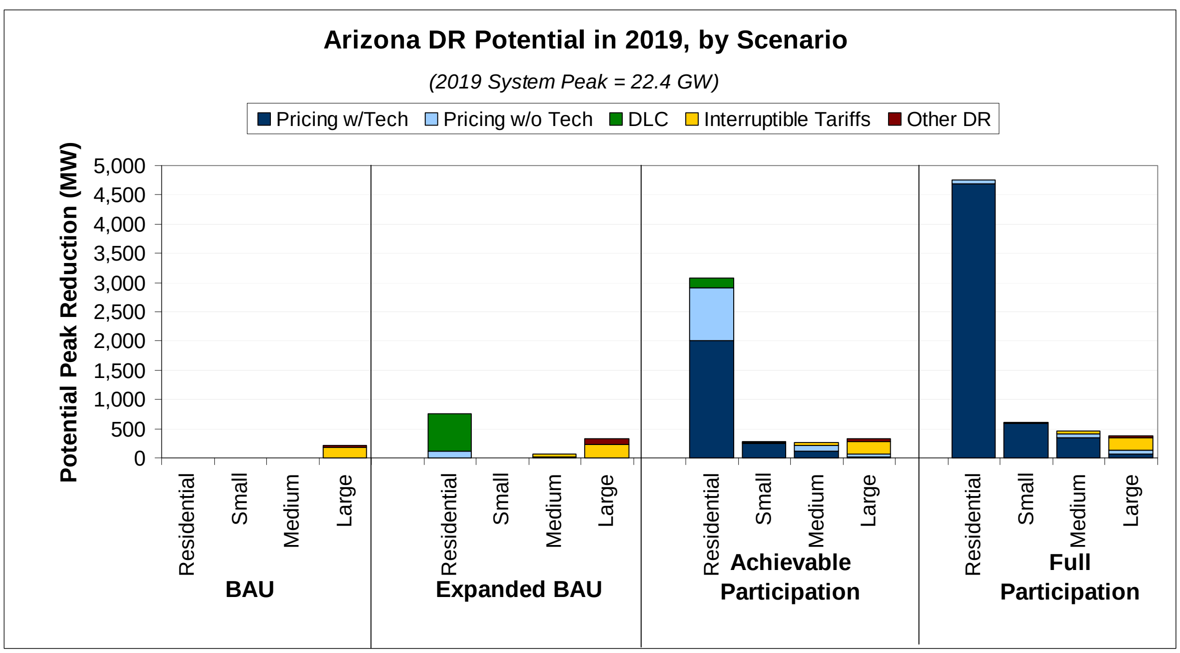
Key drivers of Arizona's demand response potential estimate include: higher-than-average residential CAC saturation of 87 percent, a customer mix that has an above average share of peak demand in the Residential and Small C&I classes (54% and 26%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. This cost-effectiveness, high residential CAC saturation and a large proportion of customers in the Residential and Small C&I sectors means that control of CAC load will be the key driver of demand response growth in Arizona.

BAU: Arizona's existing demand response comes primarily from a small Interruptible Tariffs program for large C&I customers. Note that Arizona has the largest residential TOU program in the U.S., but for reasons described previously in the report, TOU rates are excluded as a demand response option in this analysis.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class, which currently do not exist in the state. This growth is due to Arizona's high share of Residential load and high CAC saturation rate.

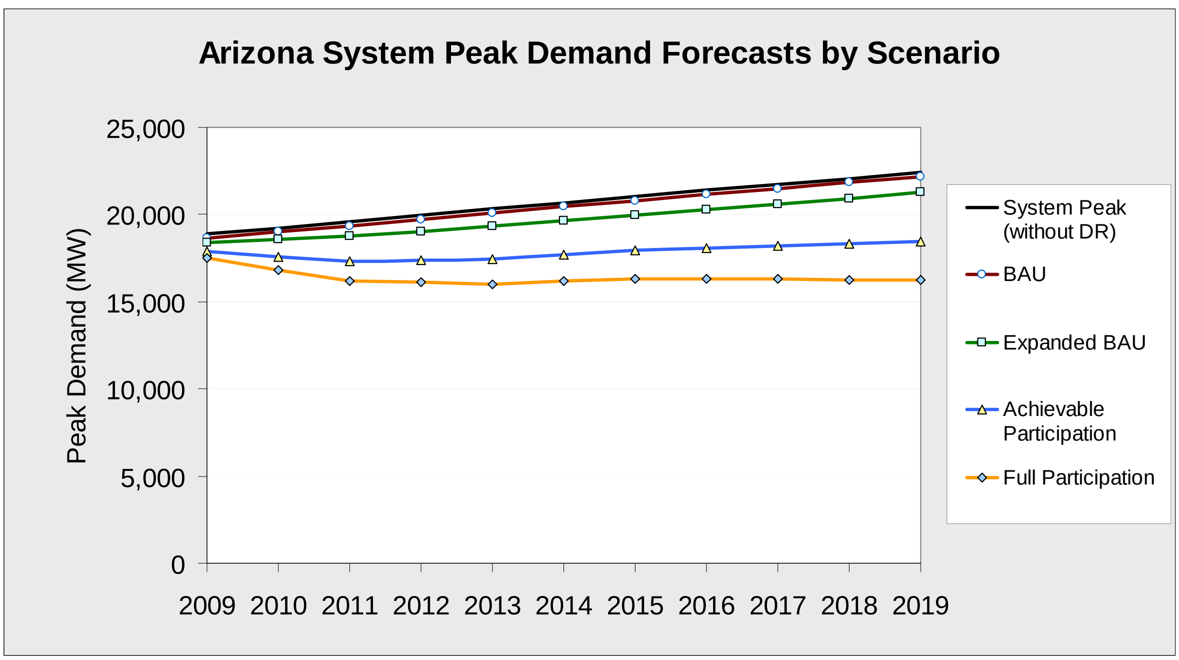
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Arizona, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	6	0.0%	184	0.8%	189	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4	0.0%	0	0.0%	6	0.0%	214	1.0%	223	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	114	0.5%	2	0.0%	11	0.1%	4	0.0%	130	0.6%
Automated/Direct Load Control	636	2.8%	6	0.0%	6	0.0%	0	0.0%	648	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	750	3.3%	7	0.0%	74	0.3%	336	1.5%	1,166	5.2%
Achievable Participation										
Pricing with Technology	2,003	8.9%	254	1.1%	119	0.5%	24	0.1%	2,400	10.7%
Pricing without Technology	913	4.1%	17	0.1%	91	0.4%	44	0.2%	1,065	4.8%
Automated/Direct Load Control	166	0.7%	1	0.0%	3	0.0%	0	0.0%	170	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	47	0.2%	47	0.2%
Total	3,082	13.7%	273	1.2%	269	1.2%	334	1.5%	3,957	17.7%
Full Participation										
Pricing with Technology	4,685	20.9%	595	2.7%	349	1.6%	70	0.3%	5,698	25.4%
Pricing without Technology	67	0.3%	11	0.1%	58	0.3%	57	0.3%	193	0.9%
Automated/Direct Load Control	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4,755	21.2%	606	2.7%	462	2.1%	377	1.7%	6,200	27.7%



Arkansas State Profile

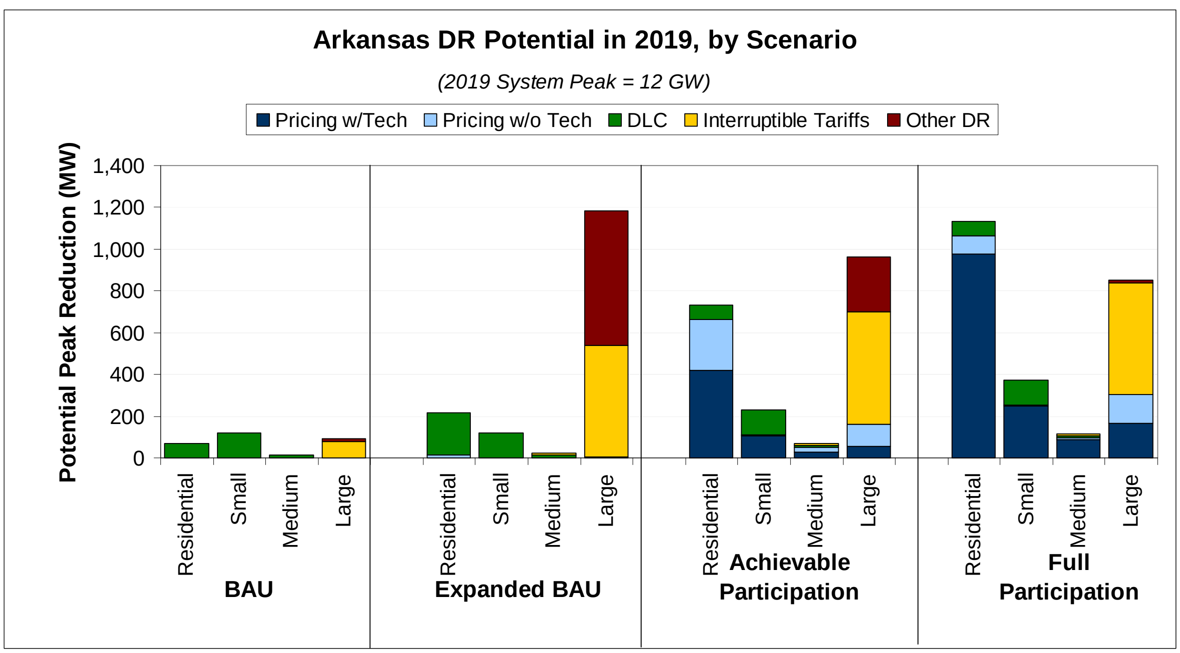
Key drivers of Arkansas's demand response potential estimate include: average residential CAC saturation of 55 percent, a customer mix that has an above average share of peak demand in the small and Large C&I classes (21% and 31%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Arkansas's existing demand response comes from all customer classes, but none of these programs are that large. DLC in all but the Large C&I class contributes the majority of the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class. This high growth is due to Arkansas's high share of Large C&I load.

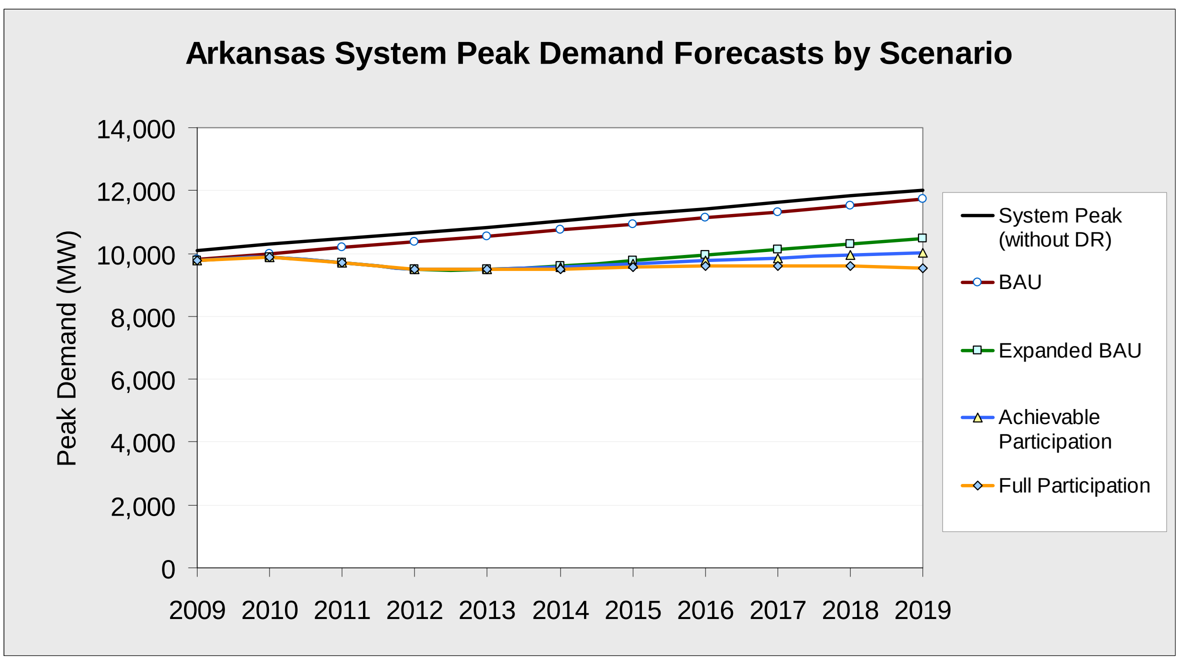
Achievable Participation: CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, CAC saturation drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Interruptible Tariffs in the Large C&I sector remain a significant portion of overall impacts and a key source of growth from BAU.



Total Potential Peak Reduction from Demand Response in Arkansas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	79	0.7%	79	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	69	0.6%	120	1.0%	13	0.1%	92	0.8%	295	2.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	1	0.0%	5	0.0%	19	0.2%
Automated/Direct Load Control	202	1.7%	120	1.0%	13	0.1%	0	0.0%	336	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	643	5.3%	643	5.3%
Total	215	1.8%	120	1.0%	23	0.2%	1,184	9.8%	1,543	12.8%
Achievable Participation										
Pricing with Technology	418	3.5%	106	0.9%	29	0.2%	57	0.5%	611	5.1%
Pricing without Technology	246	2.0%	6	0.0%	19	0.2%	104	0.9%	375	3.1%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	733	6.1%	232	1.9%	70	0.6%	960	8.0%	1,996	16.6%
Full Participation										
Pricing with Technology	978	8.1%	248	2.1%	85	0.7%	167	1.4%	1,479	12.3%
Pricing without Technology	87	0.7%	3	0.0%	9	0.1%	135	1.1%	235	2.0%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	1,134	9.4%	371	3.1%	117	1.0%	852	7.1%	2,474	20.6%



California State Profile

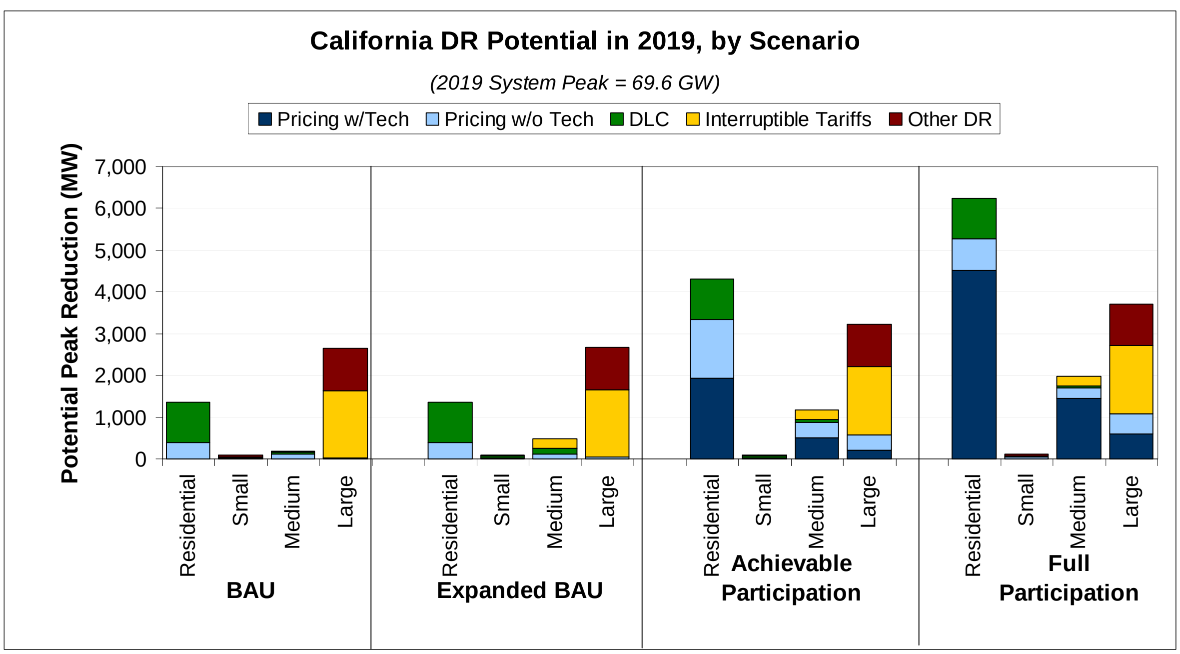
Key drivers of California's demand response potential estimate include: lower-than-average residential CAC saturation of 41 percent, a customer mix that has an above average share of peak demand in the Medium and Large C&I classes (50% combined), a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: California's existing demand response comes from three major sources – Interruptible Tariffs and Other DR in the Large C&I class and DLC in the Residential class. In addition, there is moderate demand response in place in the Small and Medium C&I classes, as well as some dynamic pricing.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. This is due to California's high share of Large C&I load, which would also allow for significant growth in the existing Interruptible Tariff. Demand response potential in the Large C&I class is nearly the same as in the BAU scenario.

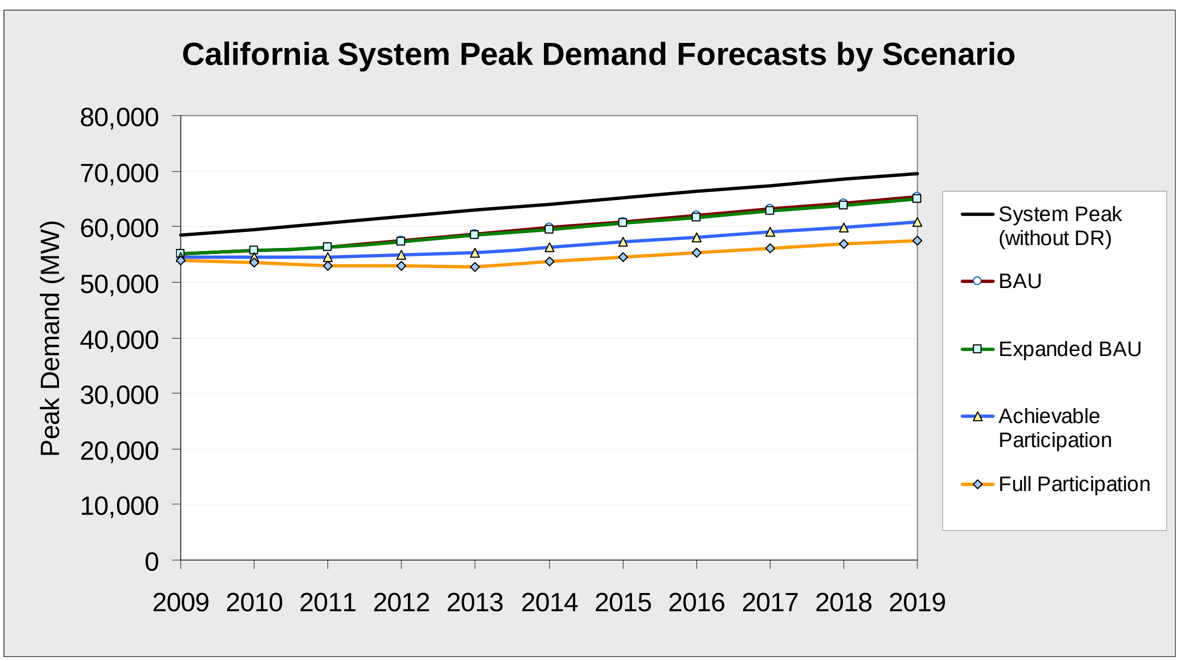
Achievable Participation: Dynamic pricing with technology in the Residential class drives a significant increase in demand response potential. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

Full Participation: Similar to the Achievable Participation scenario, dynamic pricing with technology in the Residential sector drives a significant increase in demand response potential. Demand response potential in the Large C&I class is nearly the same as in the Achievable Participation scenario.



Total Potential Peak Reduction from Demand Response in California, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	391	0.6%	21	0.0%	108	0.2%	13	0.0%	532	0.8%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.0%	1,626	2.3%	1,651	2.4%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	1,361	2.0%	88	0.1%	177	0.3%	2,651	3.8%	4,276	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	391	0.6%	21	0.0%	108	0.2%	36	0.1%	556	0.8%
Automated/Direct Load Control	970	1.4%	42	0.1%	152	0.2%	0	0.0%	1,163	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,044	1.5%
Total	1,361	2.0%	94	0.1%	494	0.7%	2,674	3.8%	4,622	6.6%
Achievable Participation										
Pricing with Technology	1,931	2.8%	0	0.0%	500	0.7%	205	0.3%	2,636	3.8%
Pricing without Technology	1,400	2.0%	29	0.0%	382	0.5%	372	0.5%	2,184	3.1%
Automated/Direct Load Control	970	1.4%	36	0.1%	67	0.1%	0	0.0%	1,072	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,043	1.5%
Total	4,302	6.2%	96	0.1%	1,182	1.7%	3,215	4.6%	8,795	12.6%
Full Participation										
Pricing with Technology	4,518	6.5%	0	0.0%	1,462	2.1%	598	0.9%	6,578	9.4%
Pricing without Technology	757	1.1%	38	0.1%	243	0.3%	482	0.7%	1,521	2.2%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	6,245	9.0%	105	0.2%	1,983	2.8%	3,719	5.3%	12,052	17.3%



Colorado State Profile

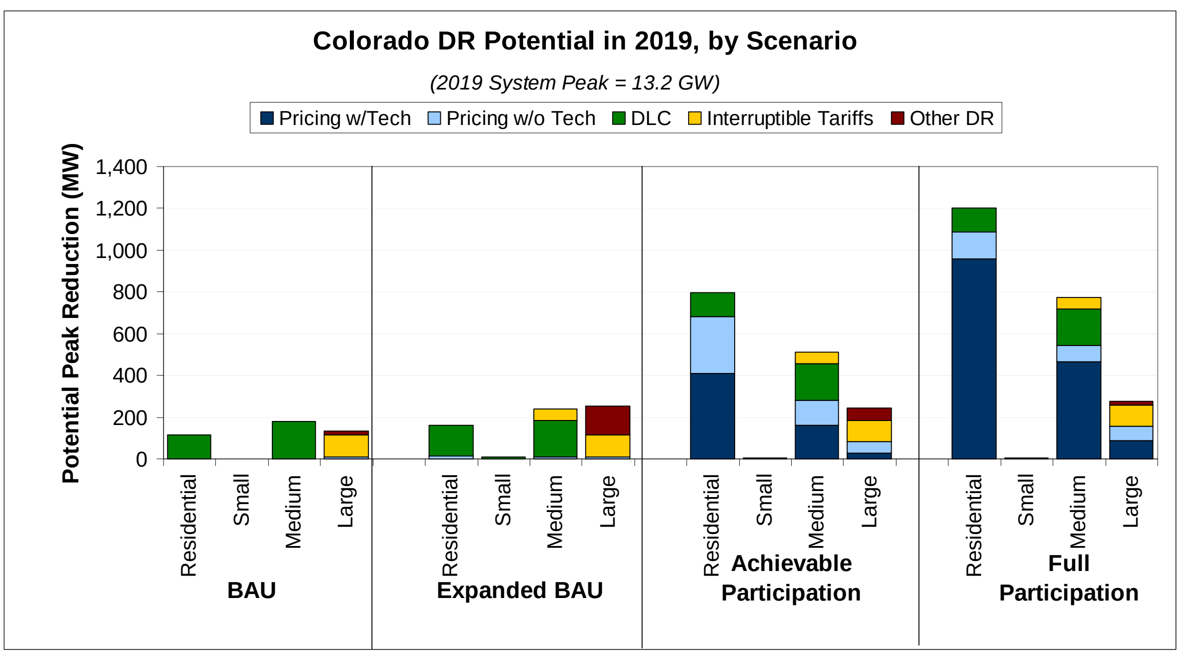
Key drivers of Colorado's demand response potential estimate include: lower-than-average residential CAC saturation of 47 percent, a customer mix that has an above average share of peak demand in Medium and Large C&I (57% combined), a moderate amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: Colorado's existing demand response comes primarily from DLC for Residential and Medium C&I customers. An Interruptible Tariff program for Large C&I customers also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. In addition, the Medium C&I class provides some Interruptible Tariffs demand response.

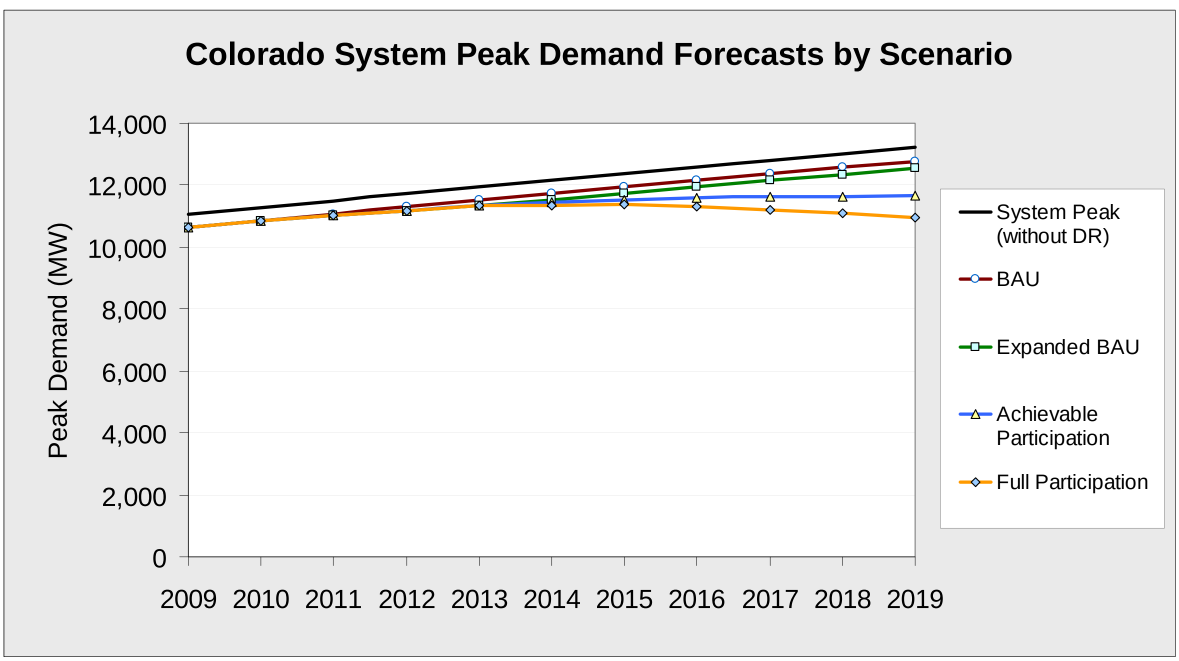
Achievable Participation: The Residential class and a large proportion of customers in the Medium C&I sector drive a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, customers in the Residential and Medium C&I sectors drive the increase in impacts. The impacts are dominated by pricing with enabling technology for Residential and Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Colorado, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	1	0.0%	0	0.0%	11	0.1%	12	0.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.8%	104	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	114	0.9%	2	0.0%	177	1.3%	135	1.0%	428	3.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	1	0.0%	8	0.1%	11	0.1%	34	0.3%
Automated/Direct Load Control	145	1.1%	7	0.1%	177	1.3%	0	0.0%	329	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	1.1%	140	1.1%
Total	159	1.2%	7	0.1%	237	1.8%	255	1.9%	659	5.0%
Achievable Participation										
Pricing with Technology	409	3.1%	0	0.0%	159	1.2%	29	0.2%	598	4.5%
Pricing without Technology	273	2.1%	3	0.0%	122	0.9%	53	0.4%	451	3.4%
Automated/Direct Load Control	114	0.9%	2	0.0%	177	1.3%	0	0.0%	293	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	0.4%	57	0.4%
Total	796	6.0%	5	0.0%	510	3.9%	244	1.8%	1,555	11.8%
Full Participation										
Pricing with Technology	958	7.3%	0	0.0%	465	3.5%	86	0.6%	1,509	11.4%
Pricing without Technology	128	1.0%	4	0.0%	77	0.6%	69	0.5%	279	2.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	1,200	9.1%	5	0.0%	772	5.8%	278	2.1%	2,256	17.1%



Connecticut State Profile

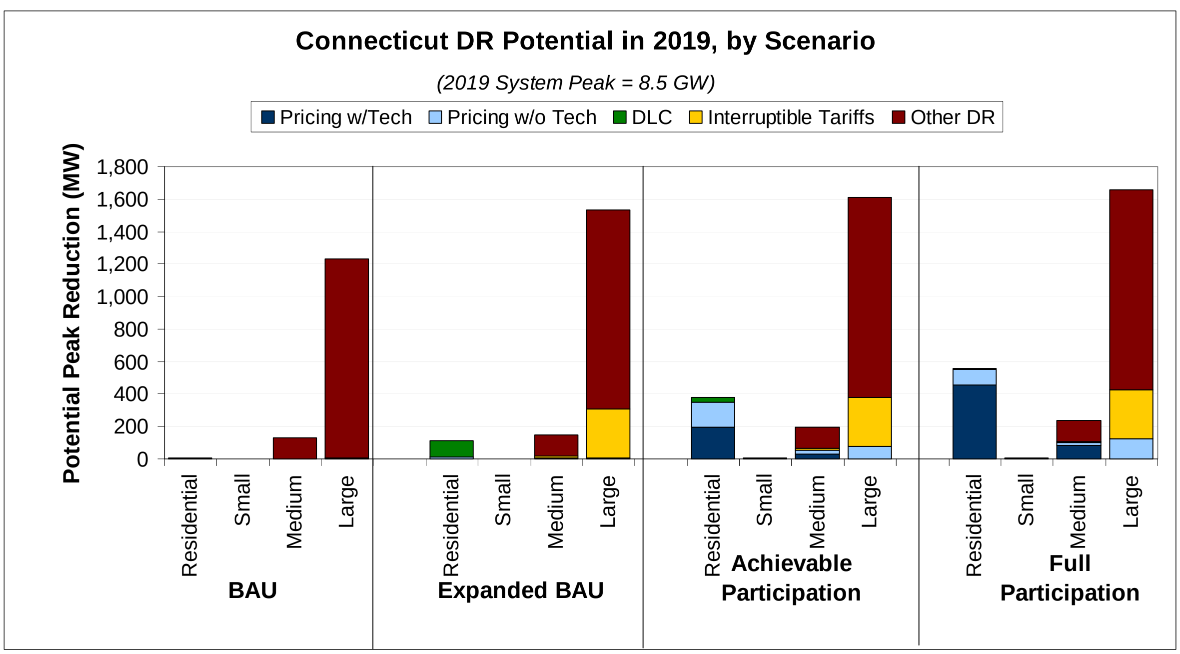
Key drivers of Connecticut's demand response potential estimate include: lower-than-average residential CAC saturation of 27 percent, a customer mix that has an above average share of peak demand in the Residential and Large C&I classes (45% and 31%, respectively), a large amount of existing demand response in the Medium and Large C&I sectors (especially Other DR), and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small and Large C&I classes.

BAU: Connecticut's existing demand response comes primarily from Other DR for Medium and Large C&I customers, the bulk of which is in the ISO New England forward capacity market.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. This high growth is due to Connecticut's large share of Large C&I load.

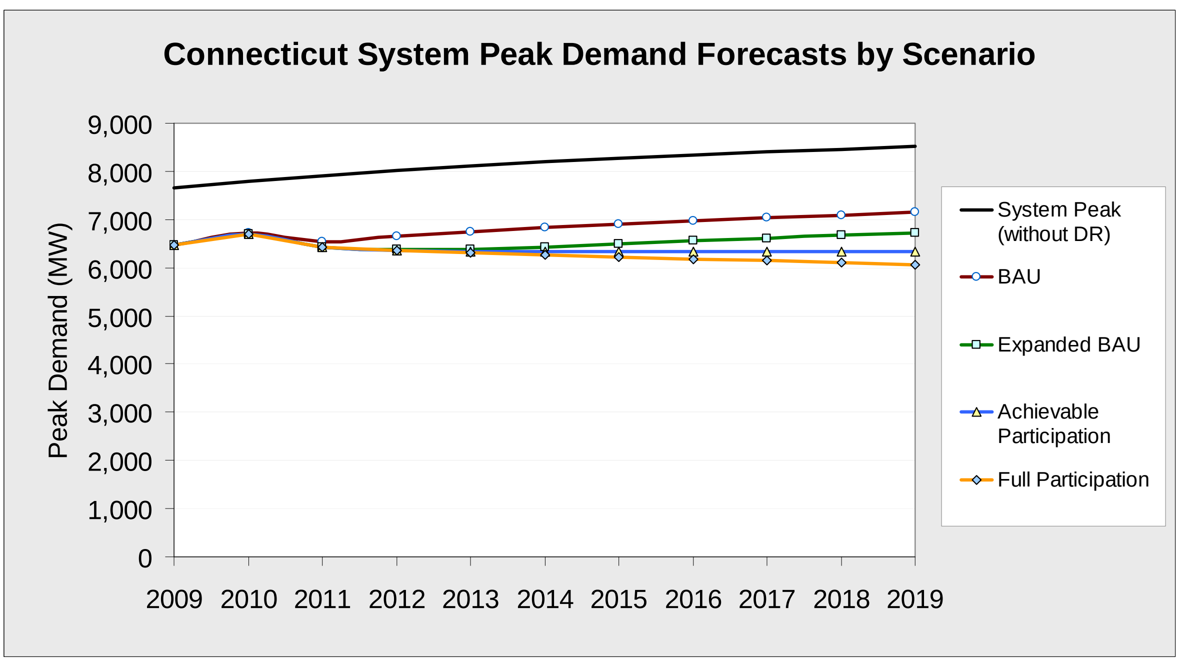
Achievable Participation: The Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

Full Participation: Similar to the Achievable Participation scenario, a large share of load in the Residential class drives the increase in impacts. Since CAC saturation is lower than average, the growth the Residential sector is not as much as is seen in hotter states for this scenario. The Large C&I class does not experience any growth in pricing with enabling technology because it is not cost effective for that class. Overall, the incremental increase in potential is small relative to the BAU.



Total Potential Peak Reduction from Demand Response in Connecticut, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	7	0.1%	0	0.0%	130	1.5%	1,233	14.5%	1,369	16.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	9	0.1%	0	0.0%	2	0.0%	3	0.0%	14	0.2%
Automated/Direct Load Control	104	1.2%	3	0.0%	4	0.1%	0	0.0%	111	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	113	1.3%	3	0.0%	146	1.7%	1,536	18.0%	1,798	21.1%
Achievable Participation										
Pricing with Technology	195	2.3%	0	0.0%	29	0.3%	0	0.0%	224	2.6%
Pricing without Technology	154	1.8%	3	0.0%	22	0.3%	75	0.9%	255	3.0%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	376	4.4%	4	0.0%	193	2.3%	1,608	18.9%	2,181	25.6%
Full Participation										
Pricing with Technology	457	5.4%	0	0.0%	84	1.0%	0	0.0%	541	6.4%
Pricing without Technology	93	1.1%	4	0.0%	15	0.2%	125	1.5%	237	2.8%
Automated/Direct Load Control	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	557	6.5%	4	0.0%	239	2.8%	1,658	19.5%	2,458	28.9%



Delaware State Profile

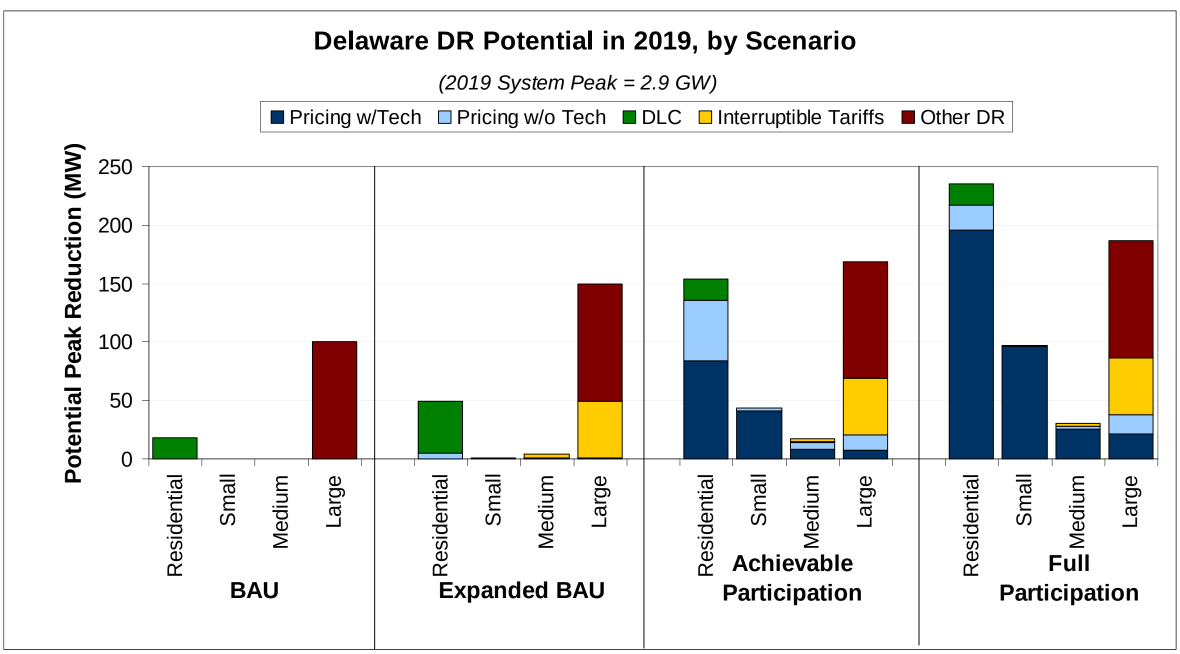
Key drivers of Delaware's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Small C&I class (36%), a moderate amount of existing demand response in the Large C&I class though Other DR, and the potential to deploy AMI at a faster-than-average rate. DLC and enabling technologies are cost effective for all customer classes in the state.

BAU: Delaware's existing demand response comes primarily from a large Other DR program for Large C&I customers. In addition, there is a moderate amount of DLC in the Residential class. Small and Medium C&I have any demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class and Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Although Delaware has a large share of Small C&I load, there is not much growth in that customer class in this scenario.

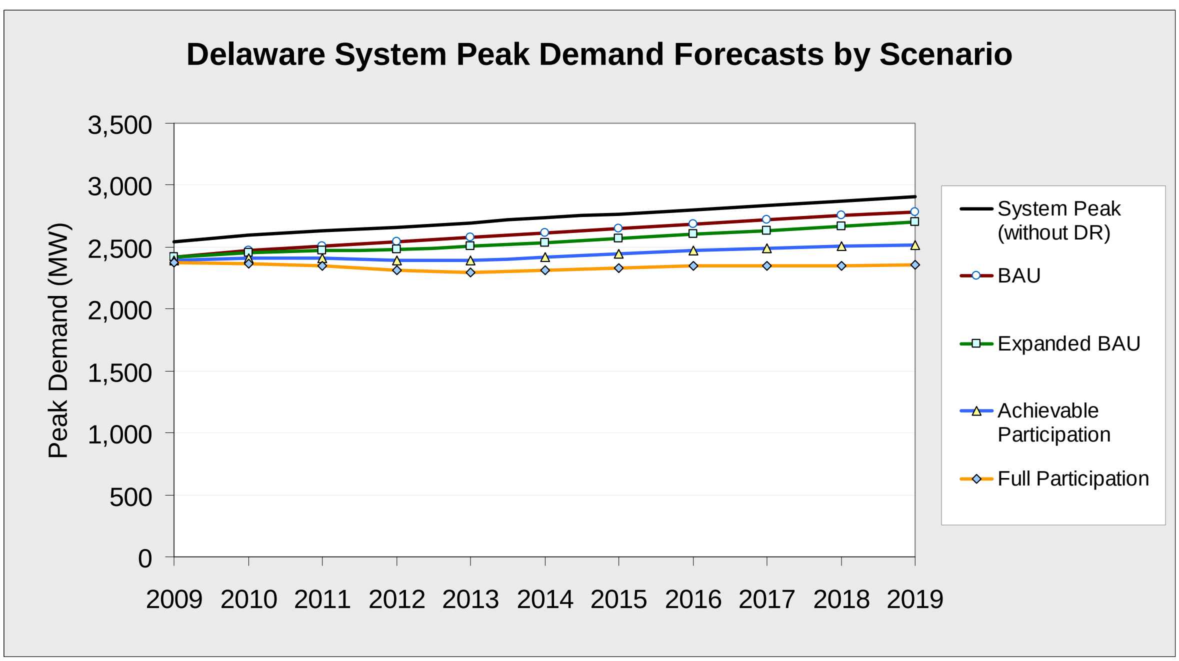
Achievable Participation: CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with enabling technology. The Small C&I class shows some growth through dynamic pricing with enabling technology.

Full Participation: Similar to the Achievable Participation scenario, residential CAC saturation combined with a large share of load in the Small C&I class drives the increase in impacts. Medium and Large C&I also show an increase due to pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Delaware, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	18	0.6%	0	0.0%	0	0.0%	100	3.4%	118	4.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	5	0.2%	0	0.0%	1	0.0%	1	0.0%	7	0.3%
Automated/Direct Load Control	44	1.5%	1	0.0%	0	0.0%	0	0.0%	46	1.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	50	1.7%	1	0.0%	4	0.1%	150	5.2%	204	7.0%
Achievable Participation										
Pricing with Technology	84	2.9%	41	1.4%	9	0.3%	7	0.2%	141	4.8%
Pricing without Technology	52	1.8%	2	0.1%	6	0.2%	13	0.5%	74	2.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	154	5.3%	44	1.5%	17	0.6%	169	5.8%	384	13.2%
Full Participation										
Pricing with Technology	196	6.7%	96	3.3%	25	0.9%	21	0.7%	338	11.6%
Pricing without Technology	22	0.8%	1	0.0%	3	0.1%	17	0.6%	43	1.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	235	8.1%	97	3.4%	30	1.0%	187	6.4%	550	18.9%



District of Columbia Profile

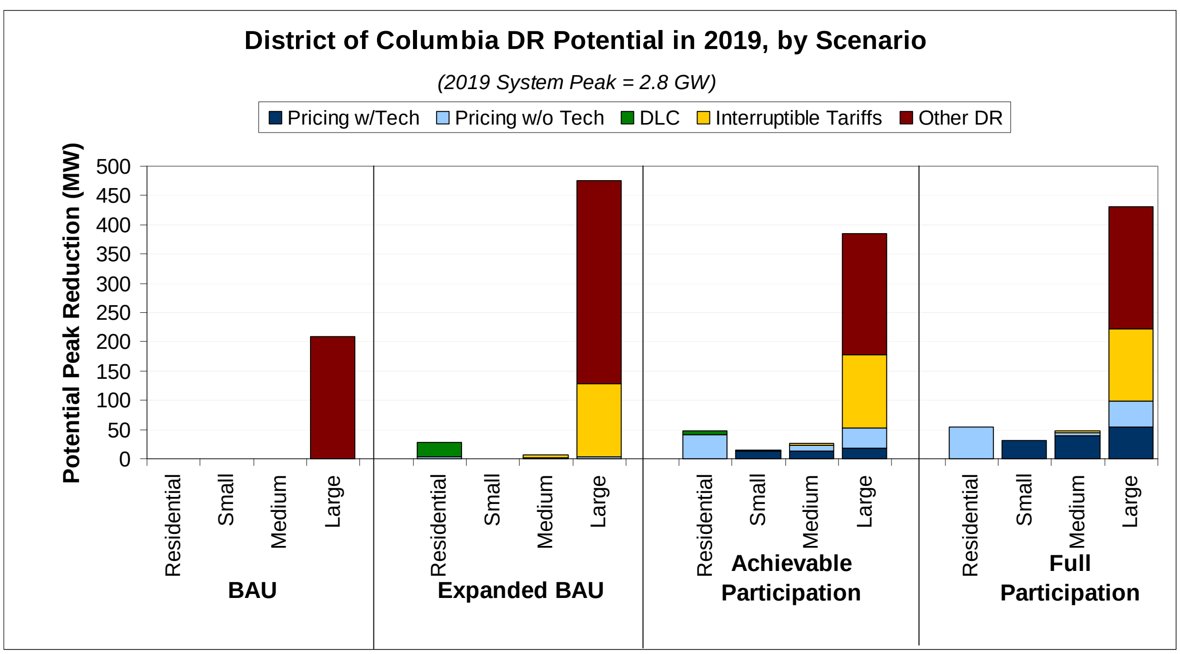
Key drivers of the District of Columbia's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Large C&I class (52%), a moderate amount of existing demand response in the Large C&I sector due to Other DR programs, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Residential class.

BAU: The District of Columbia's existing demand response comes entirely from Other DR for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Other DR expands substantially as well. This high growth is due to the District of Columbia's large share of Large C&I load.

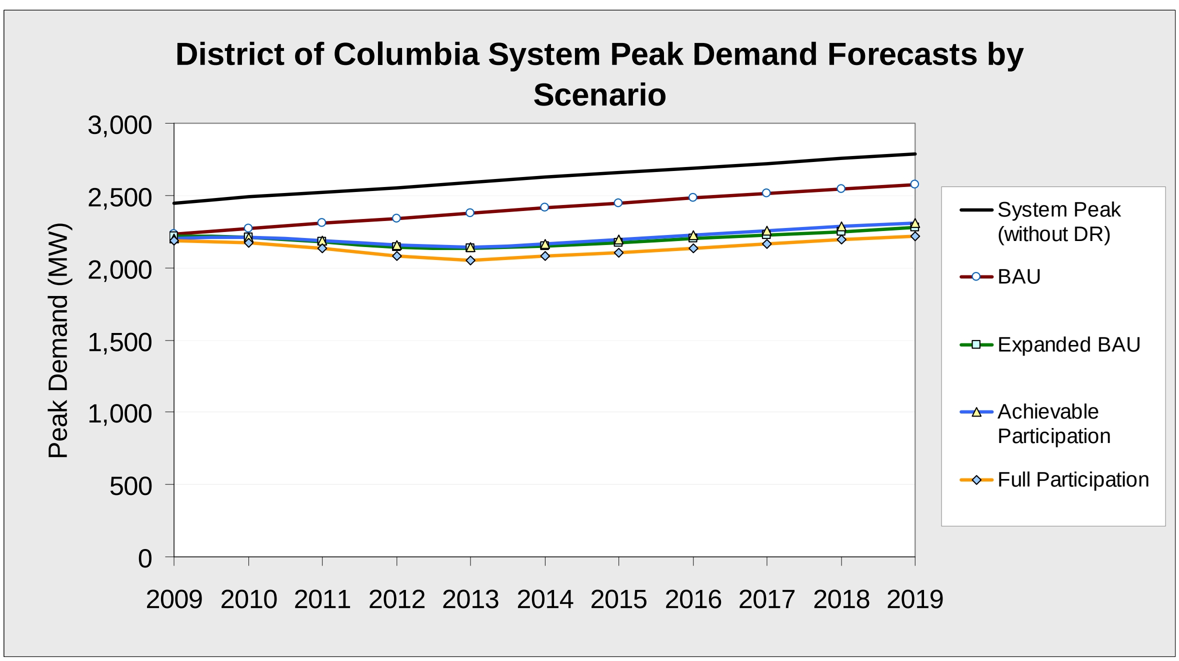
Achievable Participation: Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. This leads to lower demand response potential even though the other classes increase in demand response potential.

Full Participation: Similar to the Expanded BAU scenario, a large share of load in the Large C&I sector drives the increase in impacts. Since enabling technologies are not cost-effective for the Residential sector, the growth the Residential sector is not as much as is seen in other states for this scenario. C&I demand response potential is slightly higher than in the Achievable Participation scenario because of growth in pricing with and without enabling technology, which is cost-effective for all C&I sectors.



Total Potential Peak Reduction from Demand Response in District of Columbia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	3	0.1%	0	0.0%	1	0.1%	4	0.1%	8	0.3%
Automated/Direct Load Control	26	0.9%	0	0.0%	1	0.0%	0	0.0%	27	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	347	12.5%	347	12.5%
Total	29	1.0%	1	0.0%	6	0.2%	475	17.1%	511	18.3%
Achievable Participation										
Pricing with Technology	0	0.0%	13	0.5%	14	0.5%	19	0.7%	46	1.6%
Pricing without Technology	41	1.5%	1	0.0%	9	0.3%	34	1.2%	84	3.0%
Automated/Direct Load Control	7	0.2%	0	0.0%	0	0.0%	0	0.0%	7	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	47	1.7%	14	0.5%	27	1.0%	386	13.8%	474	17.0%
Full Participation										
Pricing with Technology	0	0.0%	31	1.1%	40	1.4%	54	2.0%	125	4.5%
Pricing without Technology	54	1.9%	0	0.0%	4	0.2%	44	1.6%	103	3.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	54	1.9%	32	1.1%	48	1.7%	431	15.5%	565	20.3%



Florida State Profile

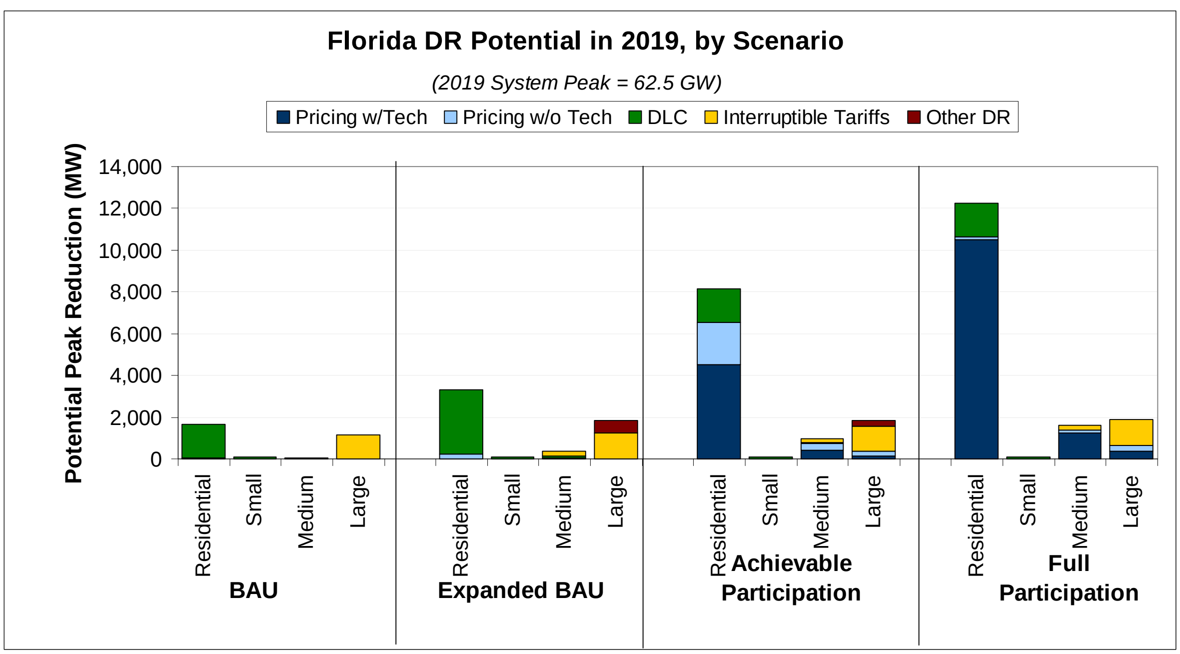
Key drivers of Florida's demand response potential estimate include: very high residential CAC saturation of 91 percent, a customer mix that has an above average share of peak demand in the Residential class (59%), a large existing residential DLC program, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class. Florida's demand response potential is highly dependent on recruiting participants from the Residential class, as is shown in the Achievable and Full Participation scenarios.

BAU: Florida's existing demand response comes primarily from DLC in the Residential class and an Interruptible Tariffs program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC for the Residential class. This is due to Florida's high share of Residential load. There is also growth in the Large C&I class due to Other DR.

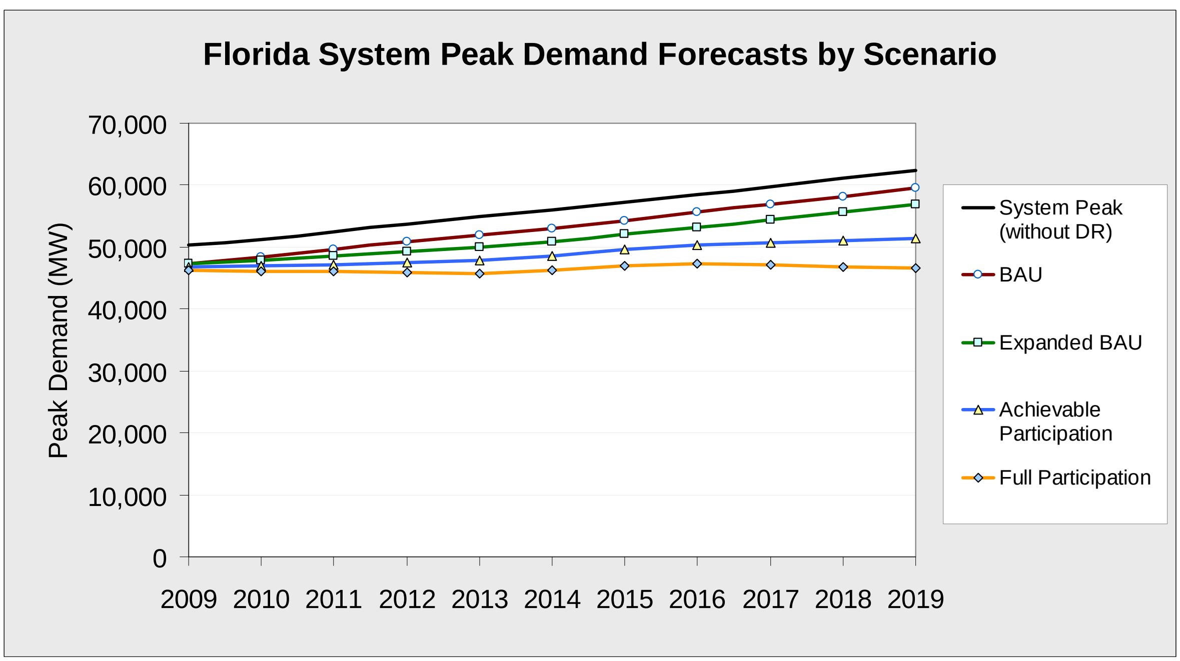
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential class drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes except Small C&I.



Total Potential Peak Reduction from Demand Response in Florida, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	42	0.1%	0	0.0%	0	0.0%	0	0.0%	42	0.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	0.0%	1,163	1.9%	1,187	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,665	2.7%	73	0.1%	24	0.0%	1,163	1.9%	2,924	4.7%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	227	0.4%	1	0.0%	34	0.1%	18	0.0%	280	0.4%
Automated/Direct Load Control	3,091	4.9%	73	0.1%	125	0.2%	0	0.0%	3,289	5.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	574	0.9%	574	0.9%
Total	3,318	5.3%	74	0.1%	346	0.6%	1,833	2.9%	5,571	8.9%
Achievable Participation										
Pricing with Technology	4,494	7.2%	0	0.0%	432	0.7%	123	0.2%	5,049	8.1%
Pricing without Technology	2,037	3.3%	16	0.0%	288	0.5%	223	0.4%	2,564	4.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	52	0.1%	0	0.0%	1,747	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	238	0.4%	239	0.4%
Total	8,154	13.1%	89	0.1%	958	1.5%	1,825	2.9%	11,026	17.7%
Full Participation										
Pricing with Technology	10,513	16.8%	0	0.0%	1,264	2.0%	358	0.6%	12,135	19.4%
Pricing without Technology	133	0.2%	21	0.0%	139	0.2%	289	0.5%	582	0.9%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	12,269	19.6%	94	0.2%	1,590	2.5%	1,889	3.0%	15,841	25.4%



Georgia State Profile

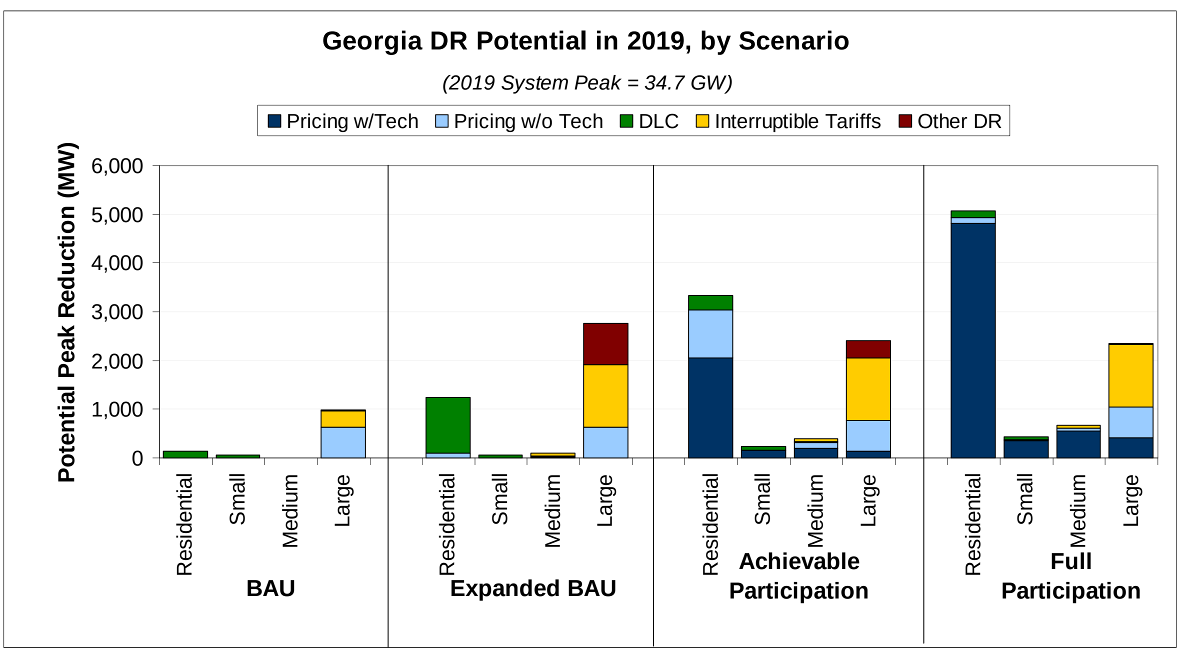
Key drivers of Georgia's demand response potential estimate include: higher-than-average residential CAC saturation of 82 percent, a customer mix that has an above average share of peak demand in the residential and Large C&I classes (50% and 25%, respectively), a moderate amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Georgia's existing demand response comes primarily from one of the largest RTP tariffs in the country for large C&I customers. An interruptible tariff program also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. This is due to Georgia's high share of Large C&I load, which would also allow for significant growth in the existing interruptible tariff. DLC also exhibits additional incremental potential in the Residential class as it is cost effective to implement.

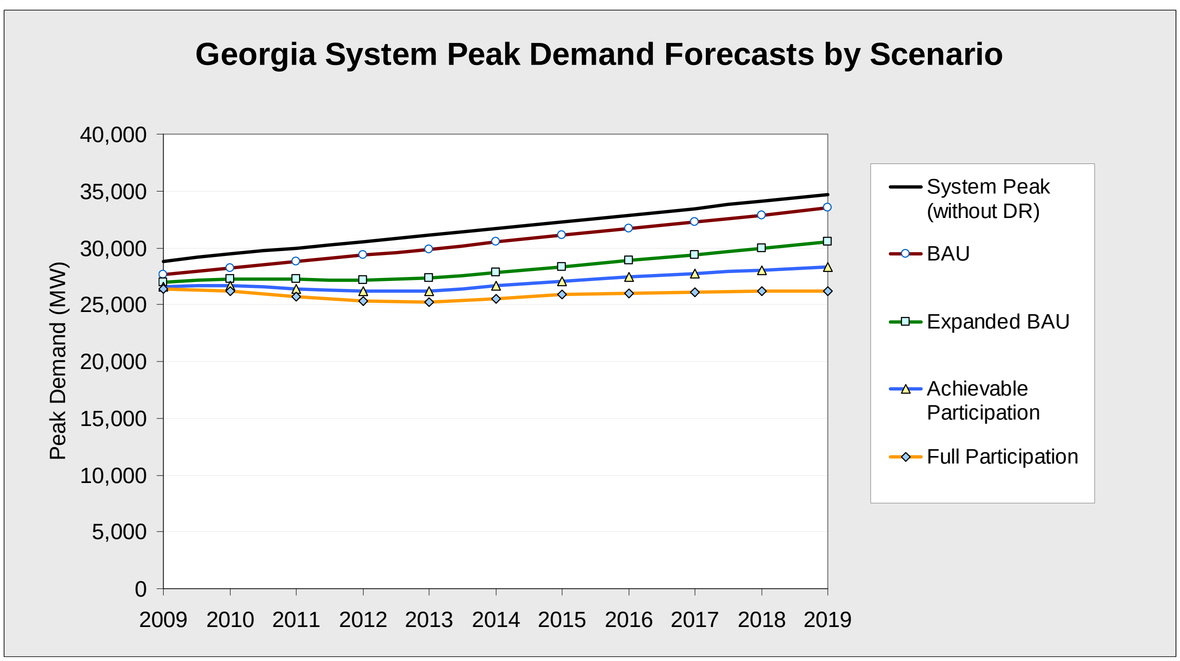
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Georgia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	2	0.0%	0	0.0%	628	1.8%	630	1.8%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	332	1.0%	332	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	130	0.4%	65	0.2%	2	0.0%	982	2.8%	1,179	3.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	95	0.3%	2	0.0%	14	0.0%	628	1.8%	739	2.1%
Automated/Direct Load Control	1,146	3.3%	63	0.2%	35	0.1%	0	0.0%	1,244	3.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	844	2.4%	844	2.4%
Total	1,241	3.6%	65	0.2%	106	0.3%	2,761	8.0%	4,174	12.0%
Achievable Participation										
Pricing with Technology	2,062	5.9%	155	0.4%	190	0.5%	143	0.4%	2,550	7.4%
Pricing without Technology	974	2.8%	9	0.0%	127	0.4%	628	1.8%	1,737	5.0%
Automated/Direct Load Control	296	0.9%	63	0.2%	14	0.0%	0	0.0%	374	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	353	1.0%	353	1.0%
Total	3,332	9.6%	227	0.7%	389	1.1%	2,414	7.0%	6,363	18.4%
Full Participation										
Pricing with Technology	4,823	13.9%	363	1.0%	557	1.6%	419	1.2%	6,161	17.8%
Pricing without Technology	114	0.3%	5	0.0%	61	0.2%	628	1.8%	807	2.3%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	5,066	14.6%	431	1.2%	678	2.0%	2,358	6.8%	8,534	24.6%



Hawaii State Profile

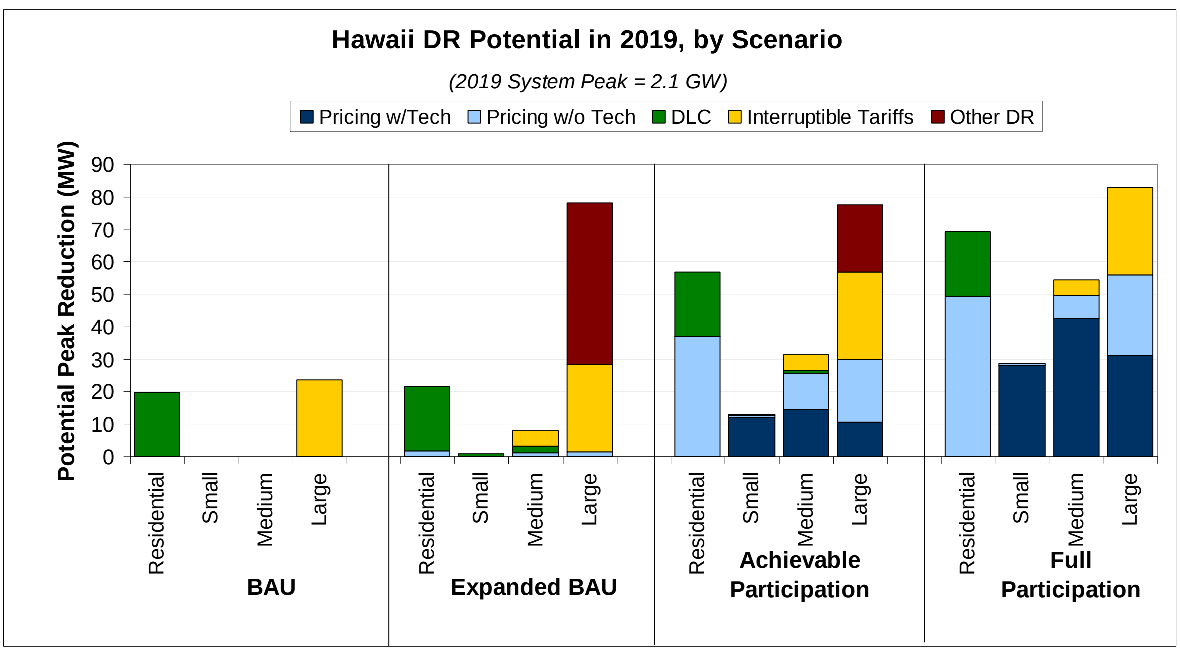
Key drivers of Georgia's demand response potential estimate include: very low CAC saturation of 17.6 percent, a customer mix that has an above average share of peak demand in the Large C&I (35%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all the C&I customer classes, however not for the Residential class.

BAU: Hawaii's existing demand response comes from DLC participation in the Residential class and Interruptible Tariff participation in the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven primarily by the Large C&I class. There is a significant increase in Interruptible Tariffs and the addition of Other DR programs. This is due to Hawaii's high share of Large C&I load.

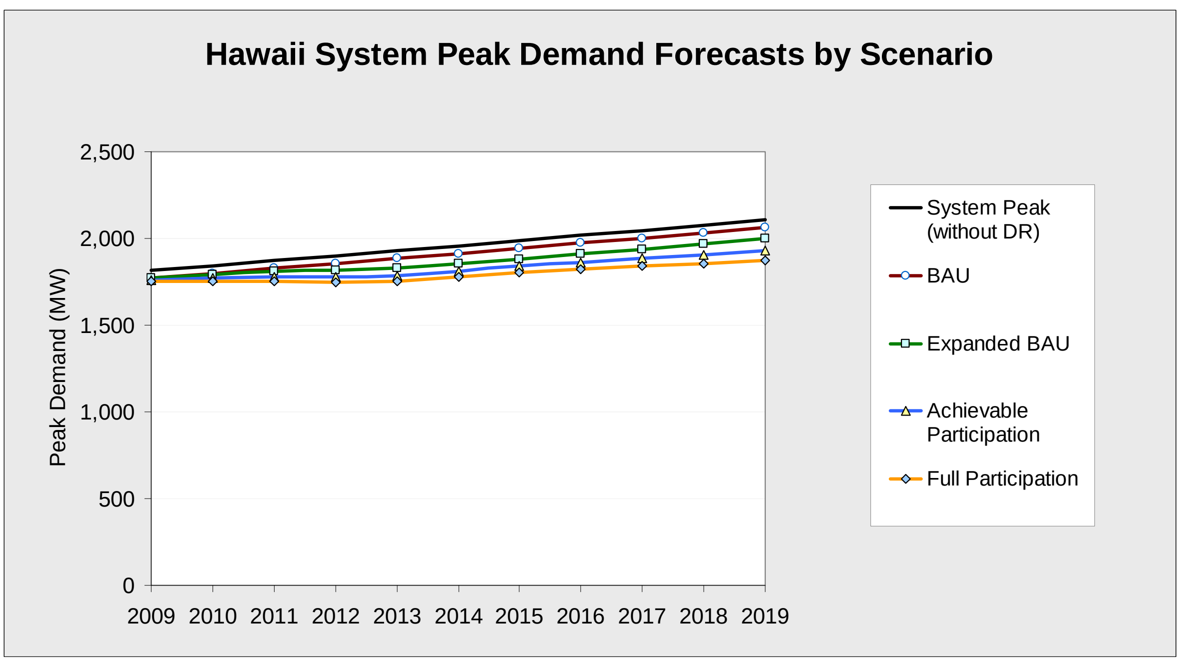
Achievable Participation: Though the Residential class is limited by a low CAC saturation and a lack of enabling technology, there is still growth in potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR, while there is moderate growth in the Small and Medium C&I classes.

Full Participation: Similar to the Achievable Participation scenario, there is growing potential across the classes in dynamic pricing, though it is limited in the Residential class due to a lack of enabling technology. Finally, the Large C&I class still exhibits strong potential in Interruptible Tariffs.



Total Potential Peak Reduction from Demand Response in Hawaii, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	24	1.1%	24	1.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	20	0.9%	0	0.0%	0	0.0%	24	1.1%	44	2.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	1	0.1%	2	0.1%	5	0.2%
Automated/Direct Load Control	20	0.9%	1	0.0%	2	0.1%	0	0.0%	23	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	50	2.4%	50	2.4%
Total	22	1.0%	1	0.0%	8	0.4%	78	3.7%	109	5.2%
Achievable Participation										
Pricing with Technology	0	0.0%	12	0.6%	15	0.7%	11	0.5%	37	1.8%
Pricing without Technology	37	1.8%	1	0.0%	11	0.5%	19	0.9%	68	3.2%
Automated/Direct Load Control	20	0.9%	0	0.0%	1	0.0%	0	0.0%	21	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	21	1.0%	21	1.0%
Total	57	2.7%	13	0.6%	31	1.5%	78	3.7%	179	8.5%
Full Participation										
Pricing with Technology	0	0.0%	28	1.3%	43	2.0%	31	1.5%	102	4.8%
Pricing without Technology	49	2.3%	1	0.0%	7	0.3%	25	1.2%	82	3.9%
Automated/Direct Load Control	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	69	3.3%	29	1.4%	54	2.6%	83	3.9%	235	11.2%



Idaho State Profile

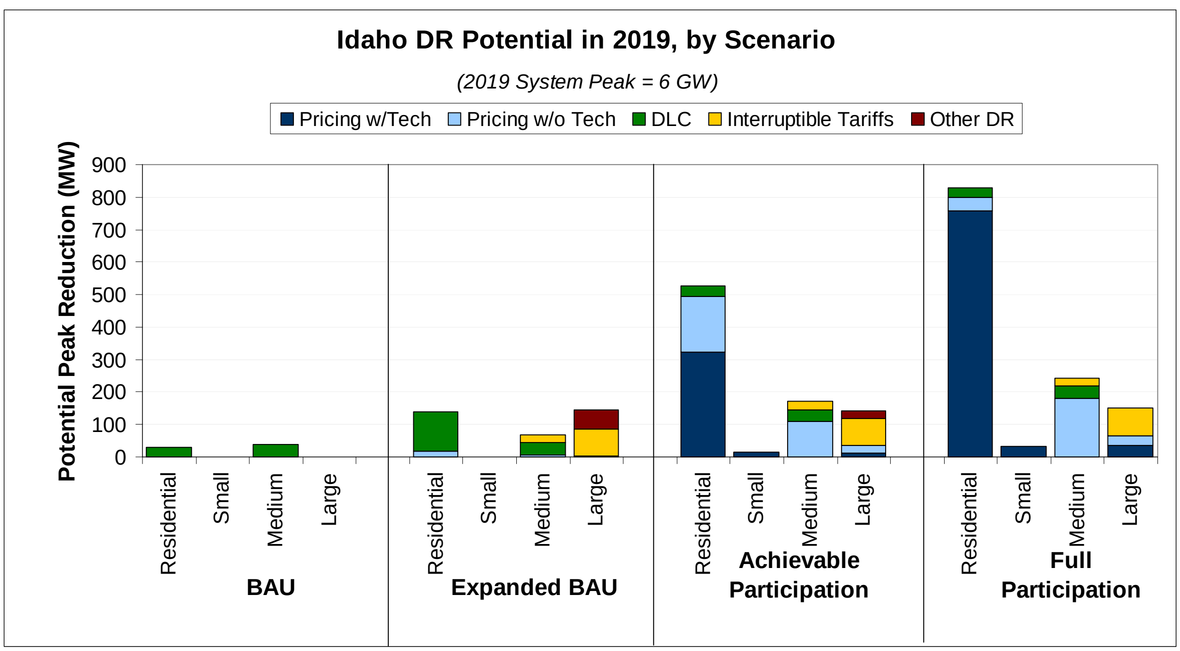
Key drivers of Idaho's demand response potential estimate significant residential CAC saturation of 66.5 percent, a customer mix that has an above average share of peak demand in the Medium C&I classes (39%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state except for the Medium C&I segment.

BAU: Idaho's existing demand response comes from DLC programs in the Residential and Medium C&I classes.

Expanded BAU: With a unique customer mix weighted towards the Residential and Medium C&I segments, growth in demand response impacts is spread across these two classes as well as in the Large C&I class. DLC potential has increased for the Residential class, while Interruptible Tariffs and Other DR make up the increase in potential found in the Medium and Large C&I classes.

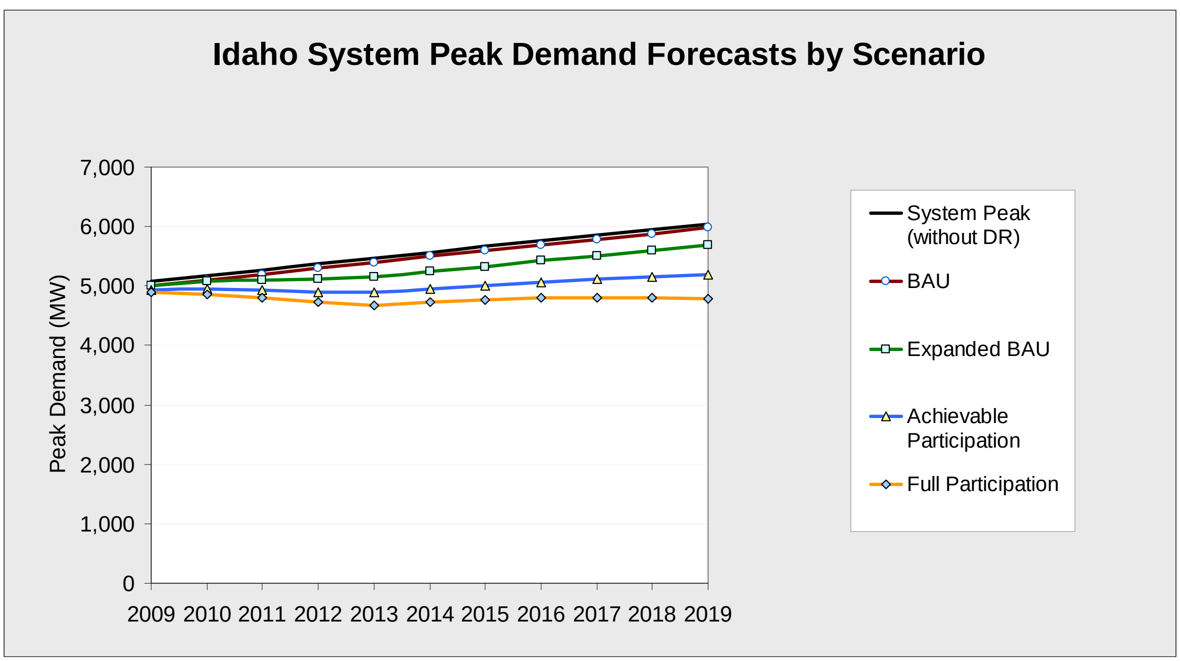
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. The size of the Medium C&I class contributes to the larger role that it plays in the state's total potential.

Full Participation: In the Full Participation scenario, the Residential class exhibits the most potential in dynamic pricing. The Medium and Large C&I classes have moderate increases from the same pricing programs, with potential from Other DR in the Large class dropping off due to an assumption that these customers would instead be enrolled in pricing programs. Potential from the Medium C&I class would be higher, but is mitigated by the lack of enabling technology for dynamic pricing.



Total Potential Peak Reduction from Demand Response in Idaho, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	16	0.3%	0	0.0%	6	0.1%	2	0.0%	24	0.4%
Automated/Direct Load Control	123	2.0%	1	0.0%	37	0.6%	0	0.0%	161	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	59	1.0%	59	1.0%
Total	139	2.3%	1	0.0%	69	1.1%	144	2.4%	354	5.9%
Achievable Participation										
Pricing with Technology	323	5.3%	14	0.2%	0	0.0%	13	0.2%	350	5.8%
Pricing without Technology	170	2.8%	1	0.0%	108	1.8%	23	0.4%	302	5.0%
Automated/Direct Load Control	32	0.5%	0	0.0%	37	0.6%	0	0.0%	69	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	24	0.4%	24	0.4%
Total	526	8.7%	15	0.3%	171	2.8%	144	2.4%	855	14.1%
Full Participation										
Pricing with Technology	757	12.5%	33	0.5%	0	0.0%	37	0.6%	826	13.7%
Pricing without Technology	41	0.7%	1	0.0%	180	3.0%	30	0.5%	252	4.2%
Automated/Direct Load Control	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	829	13.7%	33	0.6%	243	4.0%	150	2.5%	1,255	20.8%



Illinois State Profile

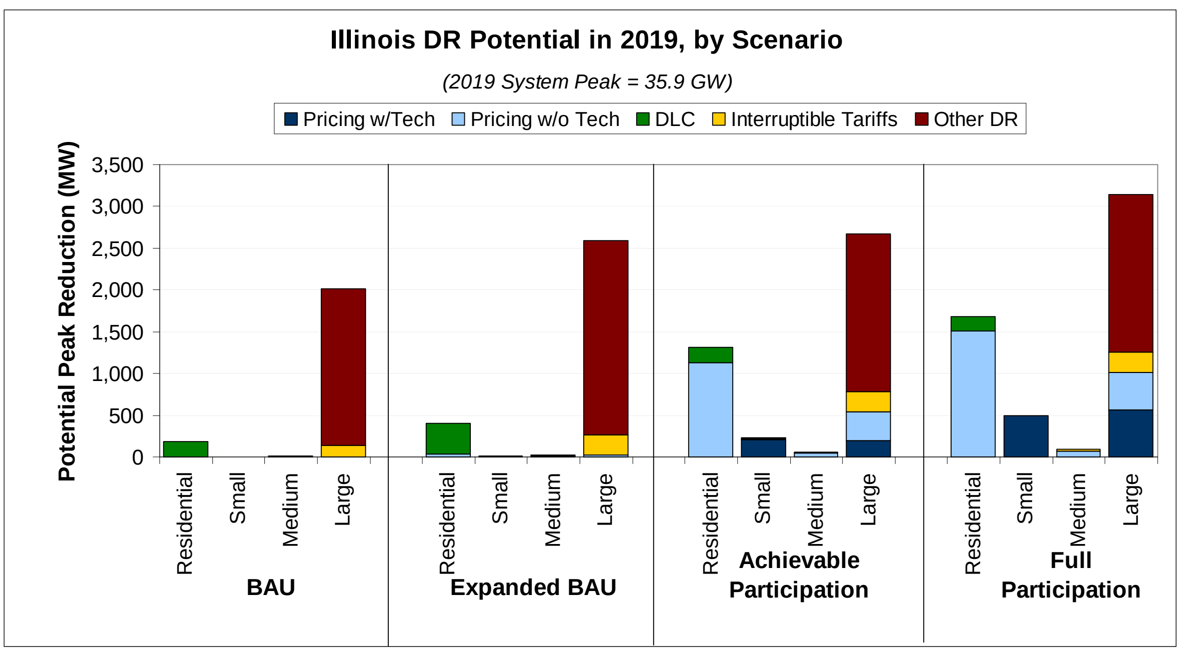
Key drivers of Illinois's demand response potential estimate include: higher-than-average residential CAC saturation of 75 percent, a customer mix that has an above average share of peak demand in the Large C&I class (42%), a moderate amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost-effective only for the Small and Large C&I classes. DLC technology is cost-effective for all customer classes in the state.

BAU: Illinois's existing demand response comes primarily from its Large C&I class, namely in the Other DR category. The Residential class contributes minimally with DLC participation.

Expanded BAU: Growth in demand response impacts is driven primarily through the Other DR programs and Interruptible Tariffs for the Large C&I class. Residential DLC exhibits small growth in the existing DLC program.

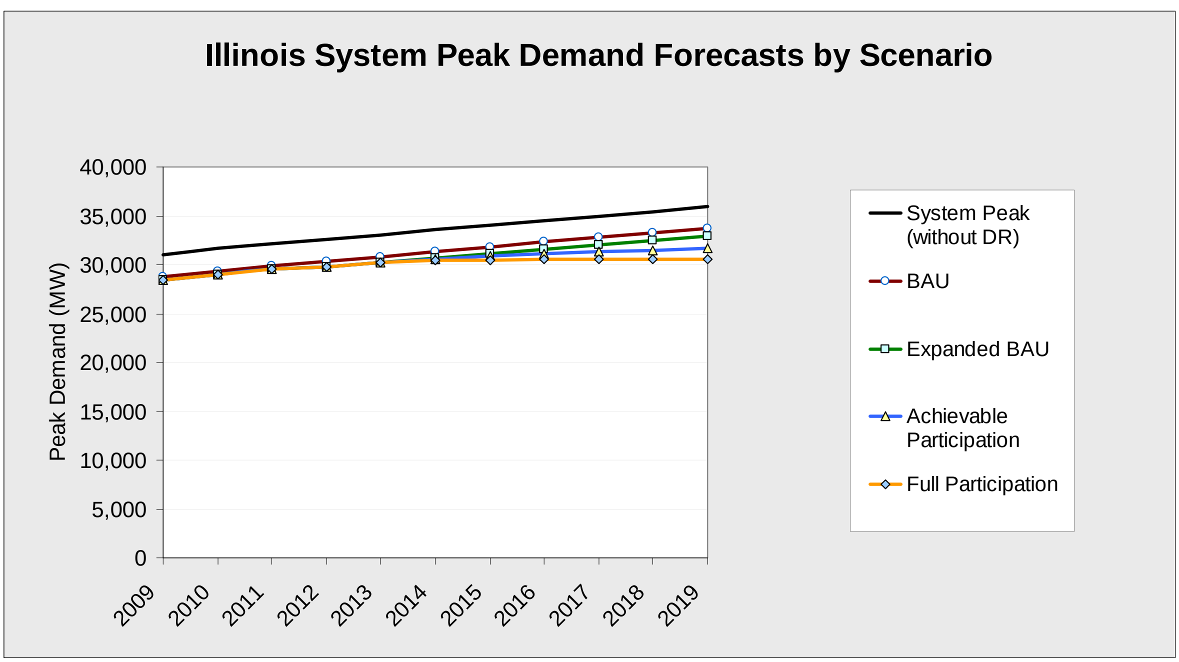
Achievable Participation: High CAC saturation in the residential sector implies significant demand response potential through pricing programs, but this is realized without enabling technology as it is not cost-effective in this class in Illinois. It is, however, cost-effective for the Small and Large C&I classes, and this is reflected in the results. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario due to higher assumed participation in pricing programs.

Full Participation: Potential increases relative to the Achievable Participation scenario due to impacts from pricing programs, limited somewhat by the lack of cost-effective enabling technology in the Residential and Medium C&I classes. The Large C&I class maintains strong potential from Interruptible Tariffs and Other DR as well.



Total Potential Peak Reduction from Demand Response in Illinois, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.0%	134	0.4%	144	0.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	179	0.5%	0	0.0%	10	0.0%	2,017	5.6%	2,206	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	39	0.1%	1	0.0%	2	0.0%	19	0.1%	61	0.2%
Automated/Direct Load Control	369	1.0%	10	0.0%	9	0.0%	0	0.0%	387	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,329	6.5%	2,329	6.5%
Total	407	1.1%	11	0.0%	26	0.1%	2,592	7.2%	3,036	8.5%
Achievable Participation										
Pricing with Technology	0	0.0%	210	0.6%	0	0.0%	192	0.5%	402	1.1%
Pricing without Technology	1,131	3.1%	13	0.0%	45	0.1%	349	1.0%	1,537	4.3%
Automated/Direct Load Control	178	0.5%	3	0.0%	4	0.0%	0	0.0%	184	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,309	3.6%	225	0.6%	63	0.2%	2,667	7.4%	4,265	11.9%
Full Participation										
Pricing with Technology	0	0.0%	492	1.4%	0	0.0%	561	1.6%	1,052	2.9%
Pricing without Technology	1,508	4.2%	8	0.0%	74	0.2%	452	1.3%	2,042	5.7%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,686	4.7%	499	1.4%	89	0.2%	3,139	8.7%	5,414	15.1%



Indiana State Profile

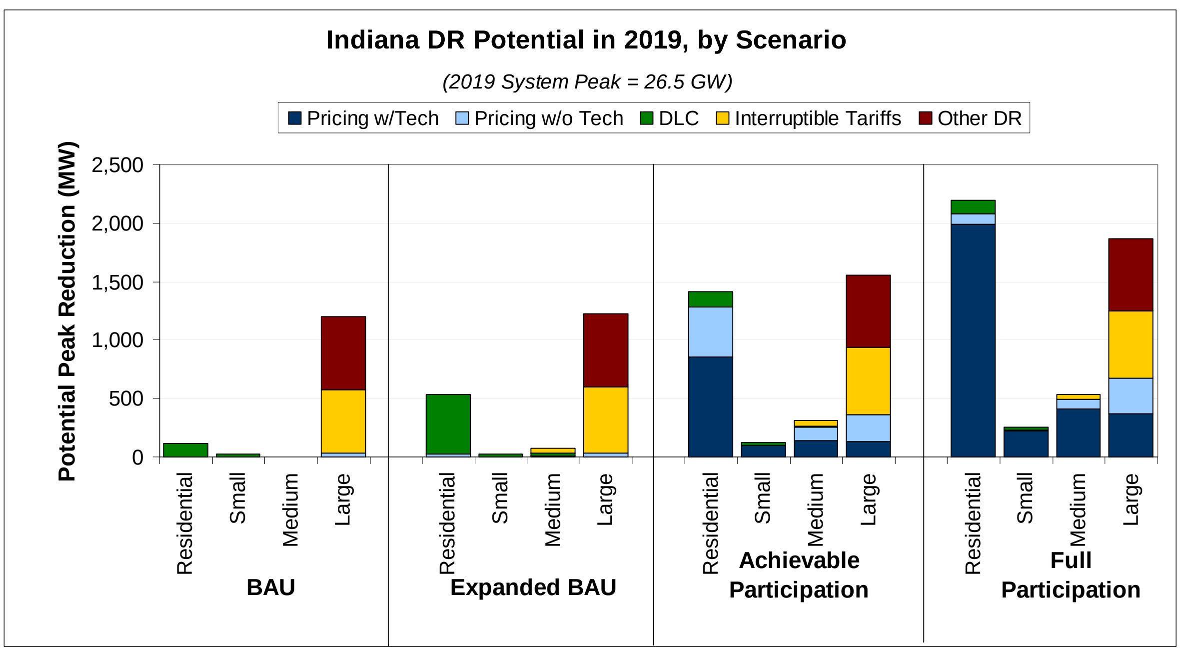
Key drivers of Indiana's demand response potential estimate include: higher-than-average residential CAC saturation of 74 percent, a customer mix that has an above average share of peak demand in the Large C&I class (35%), a moderate amount of existing demand response, and the potential to deploy AMI at an average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Indiana's existing demand response comes primarily from the Large C&I class. BAU demand response for this class is split between Interruptible Tariffs and Other DR.

Expanded BAU: Demand response potential for the Large C&I class remains largely unchanged. However, due to the high Residential CAC saturation, DLC potential in this class has grown significantly.

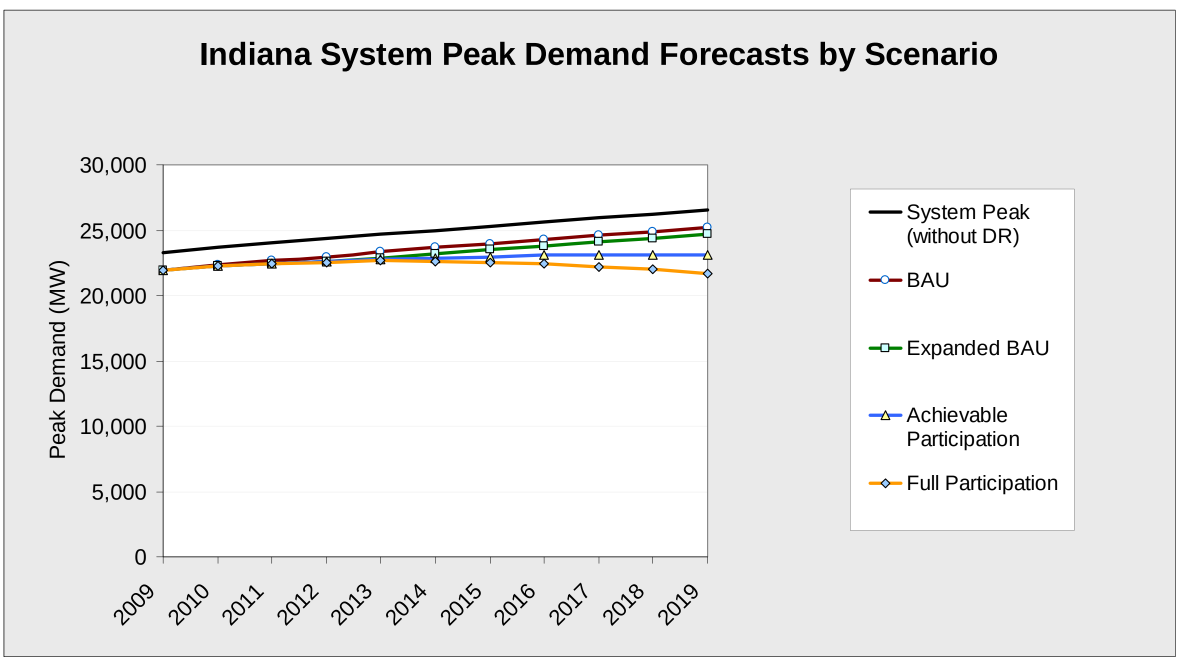
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. This is bolstered by the gains across the C&I classes due to pricing programs.

Full Participation: Continuing the trend from the Achievable Participation scenario, high CAC saturation in the residential sector and cost-effective enabling technology drive the increases in impacts from dynamic pricing programs. Potential in the C&I classes grows slightly as pricing program participation increases relative to the other scenarios.



Total Potential Peak Reduction from Demand Response in Indiana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	29	0.1%	29	0.1%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	549	2.1%	549	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	116	0.4%	23	0.1%	0	0.0%	1,199	4.5%	1,338	5.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	25	0.1%	0	0.0%	7	0.0%	29	0.1%	61	0.2%
Automated/Direct Load Control	512	1.9%	23	0.1%	24	0.1%	0	0.0%	559	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	537	2.0%	23	0.1%	78	0.3%	1,225	4.6%	1,863	7.0%
Achievable Participation										
Pricing with Technology	852	3.2%	96	0.4%	141	0.5%	128	0.5%	1,218	4.6%
Pricing without Technology	431	1.6%	6	0.0%	113	0.4%	232	0.9%	782	2.9%
Automated/Direct Load Control	131	0.5%	23	0.1%	10	0.0%	0	0.0%	163	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	1,414	5.3%	125	0.5%	311	1.2%	1,556	5.9%	3,407	12.8%
Full Participation										
Pricing with Technology	1,994	7.5%	225	0.8%	413	1.6%	373	1.4%	3,006	11.3%
Pricing without Technology	85	0.3%	3	0.0%	77	0.3%	301	1.1%	467	1.8%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	2,195	8.3%	252	0.9%	538	2.0%	1,870	7.0%	4,855	18.3%



Iowa State Profile

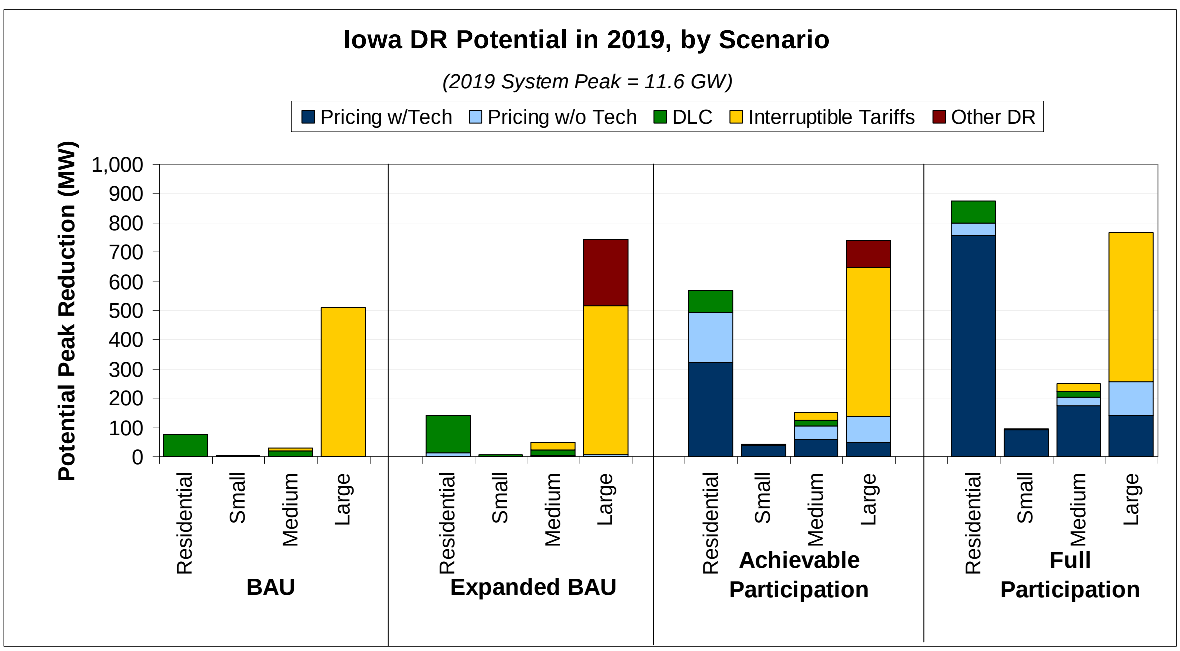
Key drivers of Iowa's demand response potential estimate include: higher-than-average residential CAC saturation of 70 percent, a customer mix that has an above average share of peak demand in the Large C&I class (34%), a small amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost effective for all customer classes.

BAU: Iowa's existing demand response comes primarily from Interruptible Tariff and Pricing program participation in the Large C&I class. There is small DLC participation in the Residential and Medium C&I classes as well.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and growth in Interruptible Tariffs participation for the Large C&I class, with slight growth in the Residential and Medium C&I classes contributing as well.

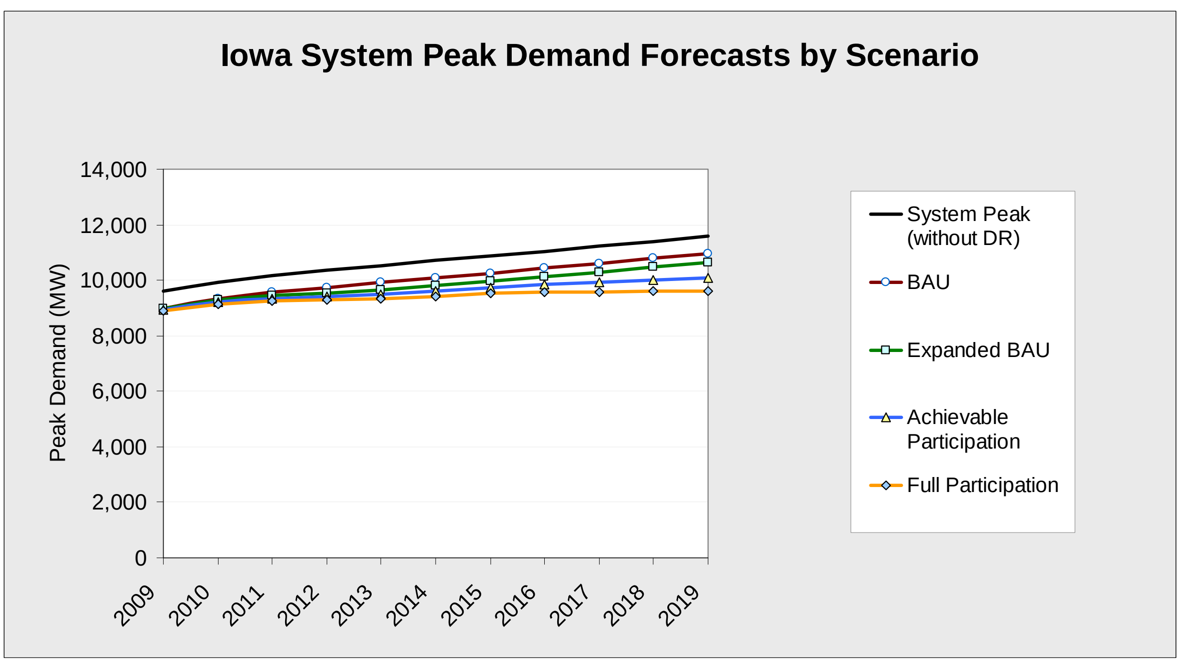
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing. The Small and Medium C&I classes show some potential, mainly through dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, growth in the Residential class is driven by pricing with enabling technology. The Small and Medium C&I classes also exhibit an increase in dynamic pricing potential. With pricing making up a larger percentage of assumed participation in the Large C&I class, Other DR does not factor into the total impacts.



Total Potential Peak Reduction from Demand Response in Iowa, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.1%	510	4.4%	521	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	76	0.7%	2	0.0%	30	0.3%	510	4.4%	618	5.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	4	0.0%	5	0.0%	23	0.2%
Automated/Direct Load Control	129	1.1%	6	0.1%	19	0.2%	0	0.0%	154	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	230	2.0%	230	2.0%
Total	142	1.2%	6	0.1%	49	0.4%	745	6.4%	942	8.1%
Achievable Participation										
Pricing with Technology	323	2.8%	40	0.3%	59	0.5%	49	0.4%	471	4.1%
Pricing without Technology	171	1.5%	2	0.0%	47	0.4%	88	0.8%	309	2.7%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	94	0.8%	94	0.8%
Total	571	4.9%	44	0.4%	151	1.3%	742	6.4%	1,507	13.0%
Full Participation										
Pricing with Technology	755	6.5%	93	0.8%	173	1.5%	142	1.2%	1,164	10.1%
Pricing without Technology	43	0.4%	1	0.0%	32	0.3%	115	1.0%	191	1.6%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	875	7.6%	97	0.8%	250	2.2%	767	6.6%	1,988	17.2%



Kansas State Profile

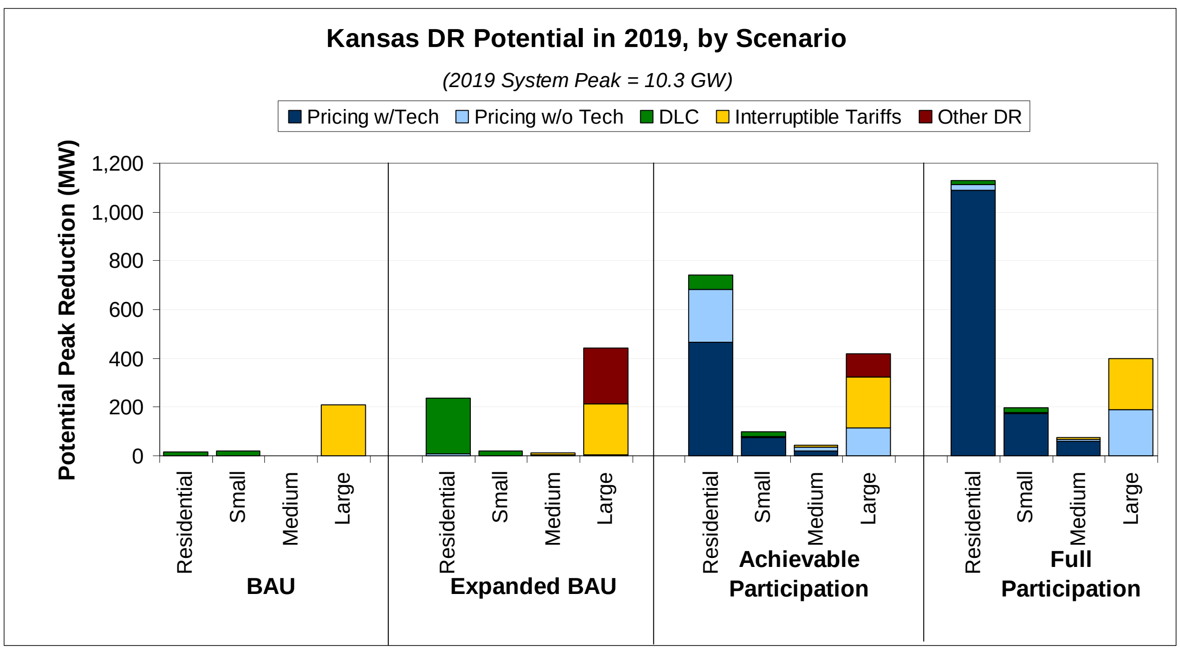
Key drivers of Kansas's demand response potential estimate include: higher-than-average residential CAC saturation of 83.7 percent, a customer mix that has a significant share of peak demand in the Residential and Large C&I classes (44% and 31%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a slower-than-average rate. Enabling technologies are cost effective for all customer classes in the state except for the Large C&I class. DLC technology is cost-effective across all classes.

BAU: Kansas's existing demand response comes primarily from Interruptible tariffs in the Large C&I class and minimal DLC participation in the Residential and Small C&I classes.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state, as well as growth in the Large C&I class's Interruptible Tariff programs and the Residential class's DLC programs.

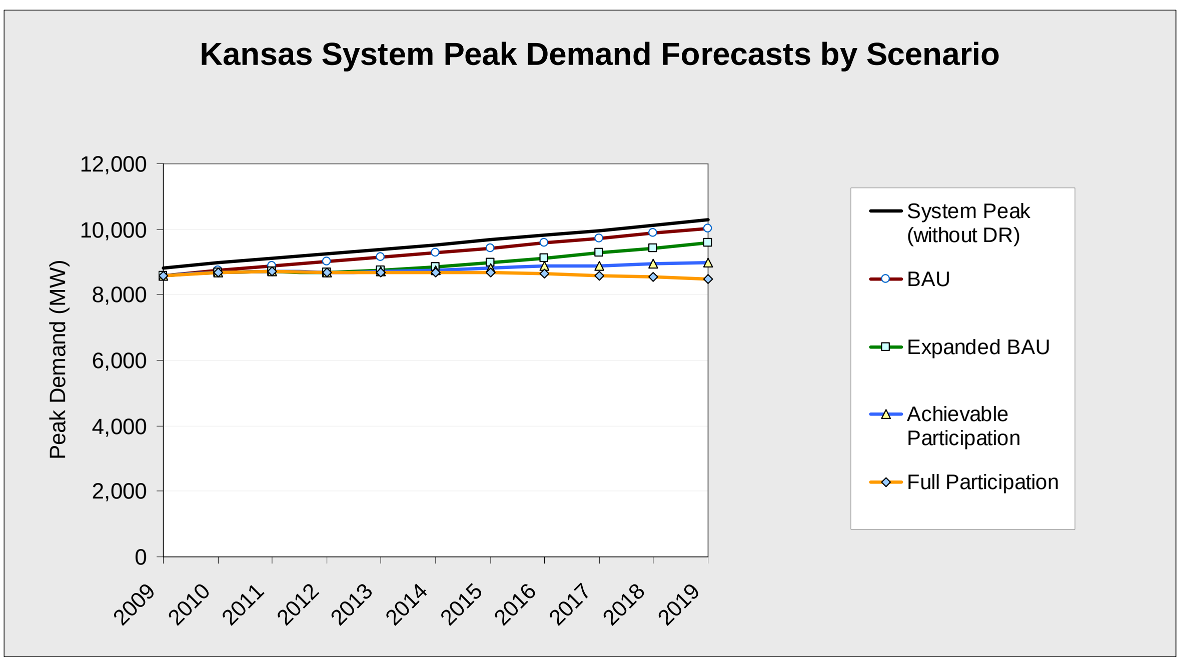
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing without technology relative to Other DR and Interruptible Tariffs.

Full Participation: High CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. With enabling technology being cost-effective for all but the Large C&I class, there are significant impacts in this category for the Small and Medium C&I classes. The Large C&I class contributes significantly through Interruptible Tariffs and pricing without enabling technology.



Total Potential Peak Reduction from Demand Response in Kansas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	211	2.0%	211	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	15	0.1%	19	0.2%	0	0.0%	211	2.0%	244	2.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	9	0.1%	0	0.0%	1	0.0%	3	0.0%	13	0.1%
Automated/Direct Load Control	226	2.2%	19	0.2%	4	0.0%	0	0.0%	248	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	229	2.2%	229	2.2%
Total	236	2.3%	19	0.2%	11	0.1%	443	4.3%	708	6.9%
Achievable Participation										
Pricing with Technology	466	4.5%	75	0.7%	20	0.2%	0	0.0%	560	5.5%
Pricing without Technology	219	2.1%	5	0.0%	16	0.2%	113	1.1%	352	3.4%
Automated/Direct Load Control	57	0.6%	19	0.2%	1	0.0%	0	0.0%	78	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	0.9%	93	0.9%
Total	742	7.2%	98	1.0%	43	0.4%	417	4.1%	1,300	12.6%
Full Participation										
Pricing with Technology	1,089	10.6%	176	1.7%	58	0.6%	0	0.0%	1,322	12.9%
Pricing without Technology	24	0.2%	3	0.0%	11	0.1%	188	1.8%	225	2.2%
Automated/Direct Load Control	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,127	11.0%	197	1.9%	75	0.7%	399	3.9%	1,798	17.5%



Kentucky State Profile

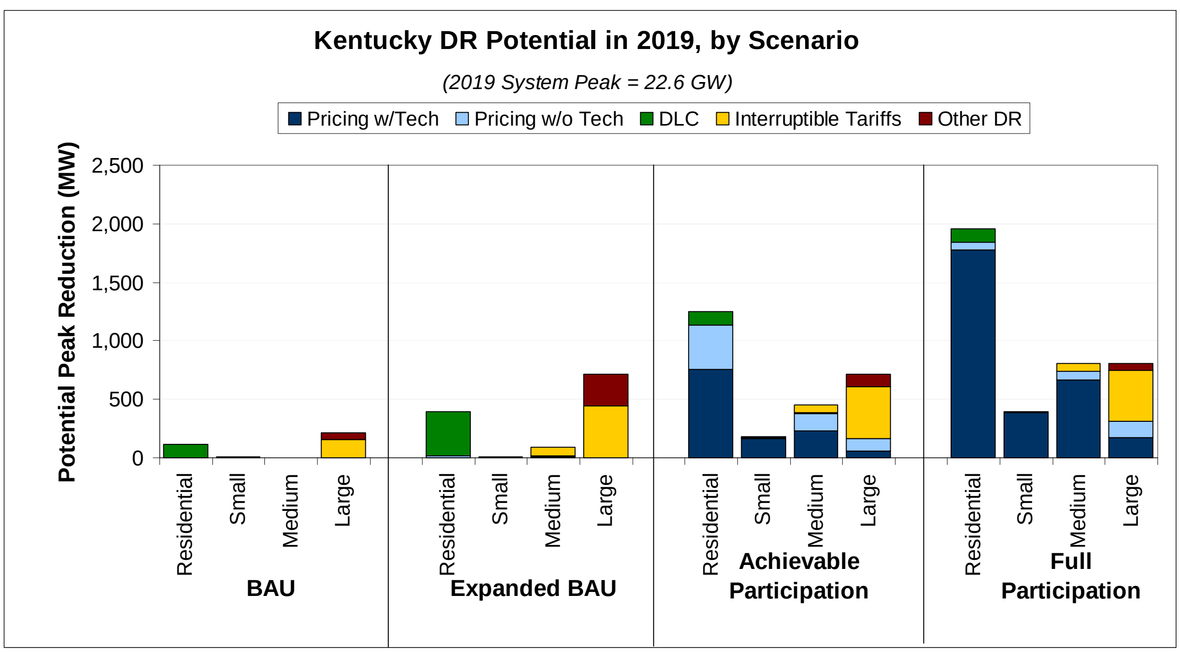
Key drivers of Kentucky's demand response potential estimate include: higher-than-average residential CAC saturation of 76 percent, a fairly typical customer mix with significant load in the Medium C&I class (30%), a minimal amount of existing demand response, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Kentucky's existing demand response comes from the Residential and Large C&I classes. DLC in the Residential class and an Interruptible Tariff in the Large C&I class make up most of the existing demand response, with Other DR in the Large C&I class also contributing.

Expanded BAU: Growth in demand response impacts is driven primarily through an increase in Other DR programs for the Large C&I class and growth in DLC for the Residential class. The Medium C&I class also gains demand response potential split mainly from an Interruptible Tariff.

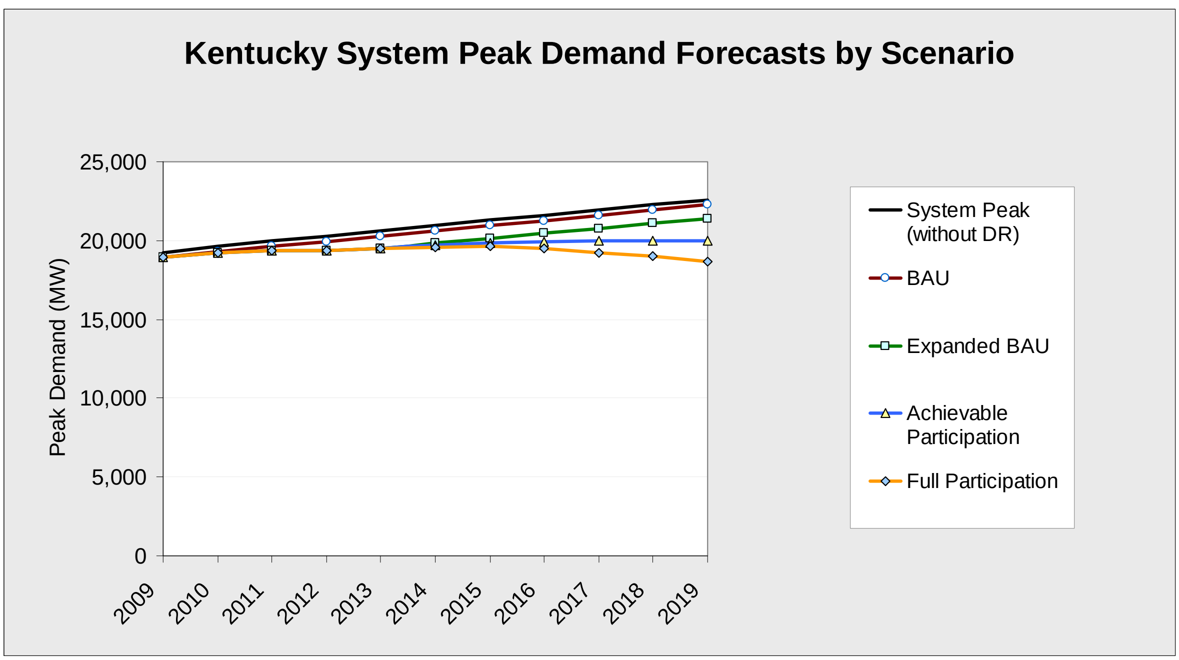
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. There is also significant growth in demand response for the Small and Medium C&I classes driven by dynamic pricing programs

Full Participation: Residential class potential increases due to dynamic pricing. Overall, high CAC saturation across the Residential, Small C&I and Medium C&I classes drives the significant dynamic pricing potential, with the Large C&I class exhibiting significant potential in Interruptible Tariff programs.



Total Potential Peak Reduction from Demand Response in Kentucky, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	155	0.7%	155	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	116	0.5%	6	0.0%	0	0.0%	211	0.9%	332	1.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.0%	4	0.0%	30	0.1%
Automated/Direct Load Control	377	1.7%	6	0.0%	12	0.1%	0	0.0%	394	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	272	1.2%	272	1.2%
Total	395	1.7%	6	0.0%	89	0.4%	713	3.2%	1,202	5.3%
Achievable Participation										
Pricing with Technology	759	3.4%	164	0.7%	227	1.0%	59	0.3%	1,209	5.4%
Pricing without Technology	377	1.7%	9	0.0%	151	0.7%	108	0.5%	645	2.9%
Automated/Direct Load Control	116	0.5%	6	0.0%	5	0.0%	0	0.0%	126	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	110	0.5%	111	0.5%
Total	1,251	5.5%	179	0.8%	452	2.0%	715	3.2%	2,596	11.5%
Full Participation										
Pricing with Technology	1,774	7.9%	383	1.7%	664	2.9%	174	0.8%	2,995	13.3%
Pricing without Technology	67	0.3%	5	0.0%	73	0.3%	140	0.6%	285	1.3%
Automated/Direct Load Control	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	1,957	8.7%	394	1.7%	806	3.6%	807	3.6%	3,963	17.5%



Louisiana State Profile

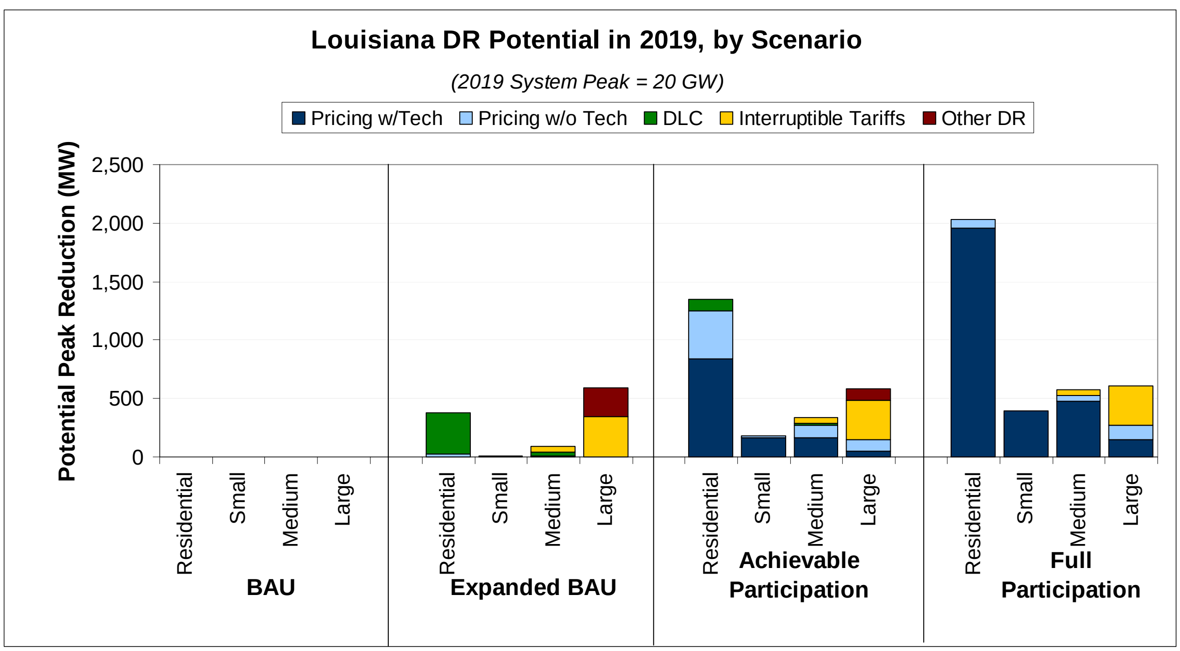
Key drivers of Louisiana's demand response potential estimate include: higher-than-average residential CAC saturation of 75.5 percent, an average customer mix, no existing demand response programs, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: A review of the available data did not identify any existing demand response programs in Louisiana.

Expanded BAU: Growth in demand response impacts under this scenario are driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class, and a DLC program for the Residential class. The Residential class has much potential for DLC and dynamic pricing due to its high CAC saturation.

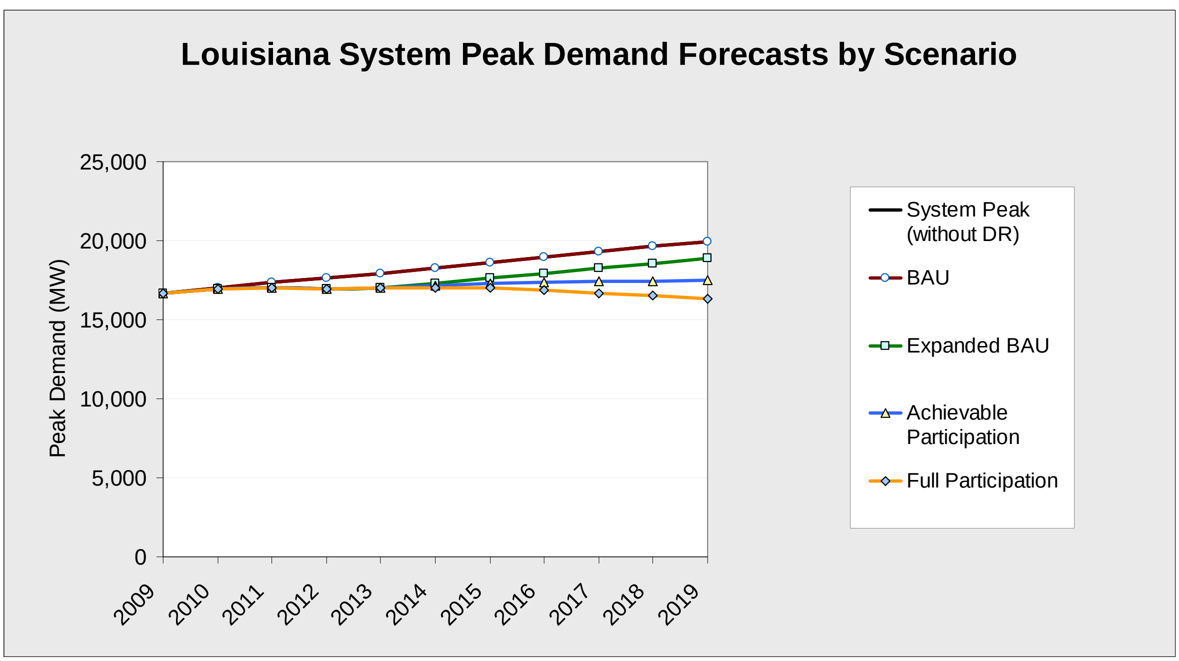
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a significant share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Lastly, an Interruptible Tariff in the Large C&I class contributes significantly to Louisiana's demand response potential under this scenario.



Total Potential Peak Reduction from Demand Response in Louisiana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	24	0.1%	0	0.0%	7	0.0%	4	0.0%	35	0.2%
Automated/Direct Load Control	356	1.8%	4	0.0%	38	0.2%	0	0.0%	398	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	244	1.2%	244	1.2%
Total	380	1.9%	5	0.0%	94	0.5%	589	3.0%	1,068	5.4%
Achievable Participation										
Pricing with Technology	837	4.2%	168	0.8%	163	0.8%	51	0.3%	1,220	6.1%
Pricing without Technology	417	2.1%	9	0.0%	109	0.5%	93	0.5%	628	3.1%
Automated/Direct Load Control	91	0.5%	1	0.0%	15	0.1%	0	0.0%	107	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	99	0.5%	100	0.5%
Total	1,345	6.7%	179	0.9%	336	1.7%	585	2.9%	2,445	12.3%
Full Participation										
Pricing with Technology	1,959	9.8%	394	2.0%	477	2.4%	150	0.7%	2,979	14.9%
Pricing without Technology	74	0.4%	5	0.0%	53	0.3%	121	0.6%	252	1.3%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,033	10.2%	399	2.0%	579	2.9%	612	3.1%	3,622	18.1%



Maine State Profile

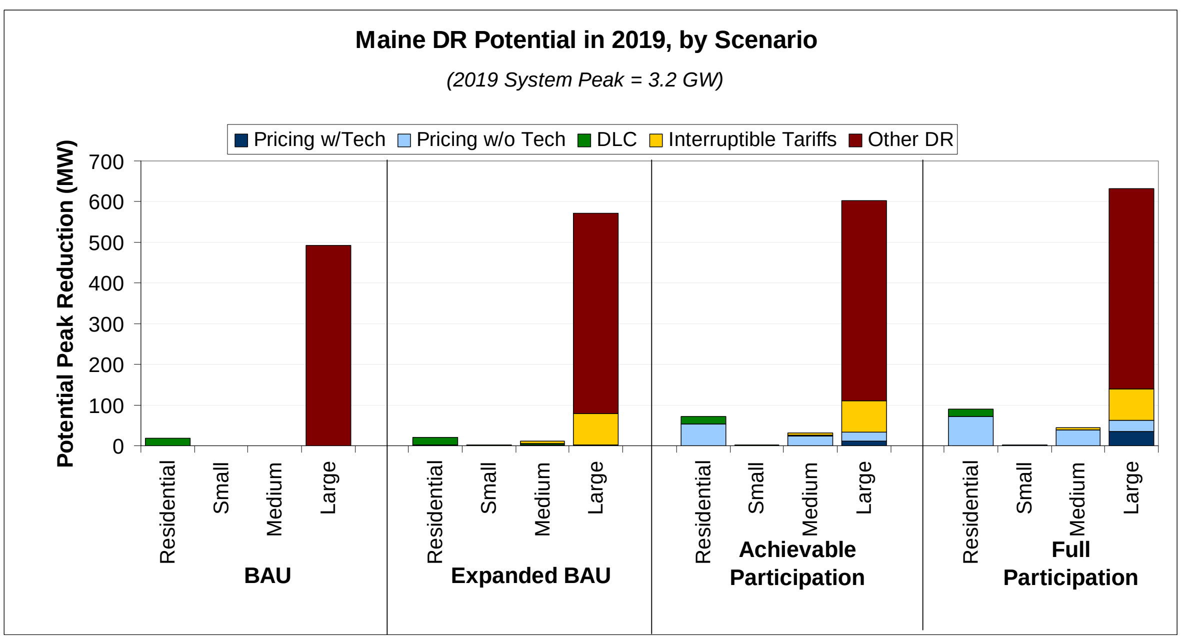
Key drivers of Maine's demand response potential estimate include: lower than average residential CAC saturation of 14%, above average share of peak demand (34%) in the Large C&I classes, and a large amount of existing demand response. Pricing with enabling technologies are only cost effective for the Large C&I class. DLC is cost effective for all classes.

BAU: Maine's existing demand response comes predominantly from the Large C&I class through participation in the ISO New England forward capacity market. These impacts account for over 60% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. This is due to Maine's above average share of Large C&I load, which would also allow for some growth in the Other DR category.

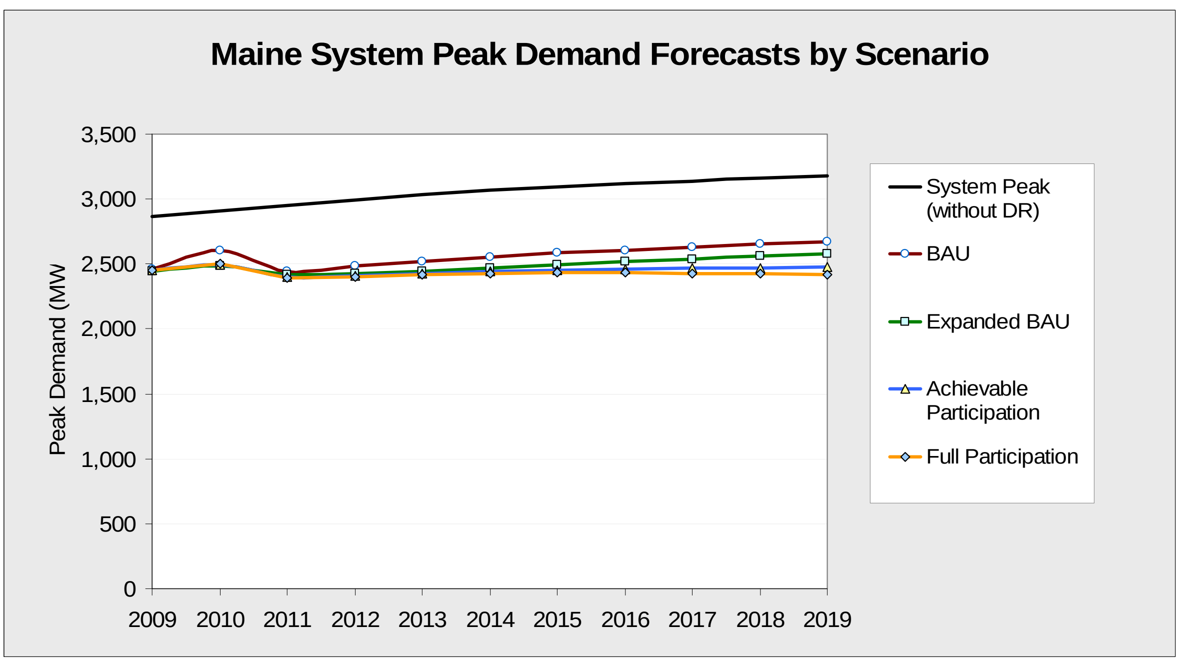
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology, which is cost effective for the Large C&I class, contributes additional potential for that customer group.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by pricing without enabling technologies for all customer classes. For the Large C&I class, pricing with enabling technology also contributes to the total potential.



Total Potential Peak Reduction from Demand Response in Maine, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	18	0.6%	0	0.0%	0	0.0%	492	15.4%	510	16.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	1	0.0%	1	0.0%	4	0.1%
Automated/Direct Load Control	18	0.6%	1	0.0%	5	0.2%	0	0.0%	25	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	20	0.6%	1	0.0%	12	0.4%	571	17.9%	604	19.0%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	12	0.4%	12	0.4%
Pricing without Technology	53	1.7%	1	0.0%	23	0.7%	21	0.7%	99	3.1%
Automated/Direct Load Control	18	0.6%	0	0.0%	2	0.1%	0	0.0%	21	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	72	2.2%	1	0.0%	31	1.0%	603	18.9%	706	22.2%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	34	1.1%	34	1.1%
Pricing without Technology	71	2.2%	1	0.0%	39	1.2%	28	0.9%	139	4.4%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	89	2.8%	1	0.0%	45	1.4%	631	19.8%	766	24.1%



Maryland State Profile

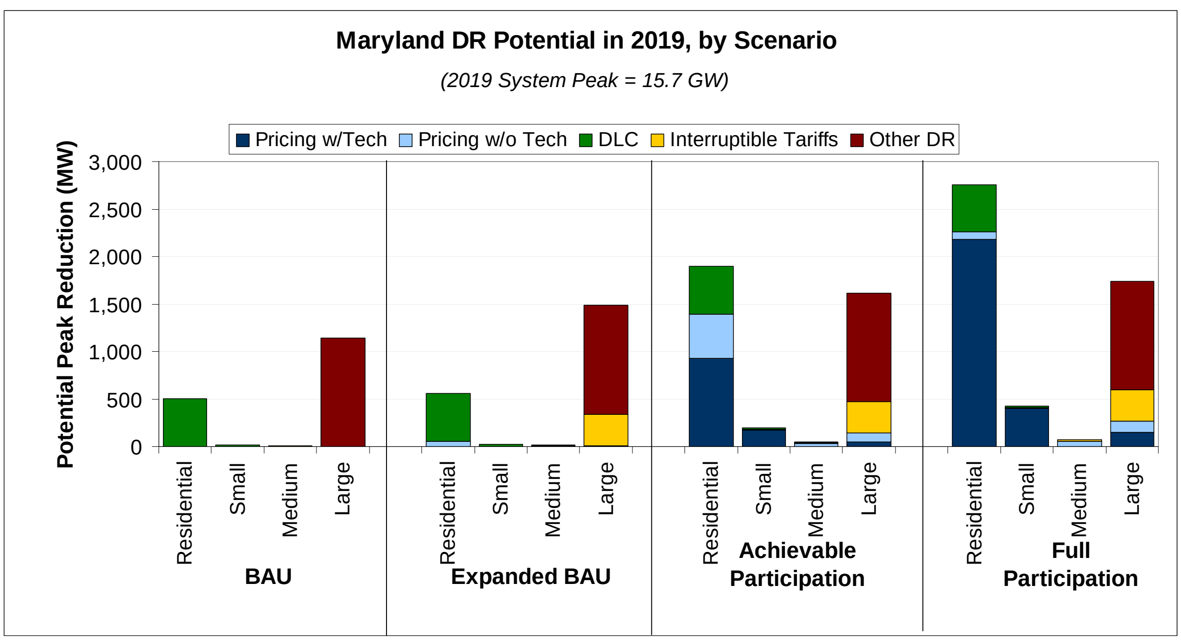
Key drivers of Maryland's demand response potential estimate include: higher-than-average residential CAC saturation of 78%, above average share of peak demand (48%) in the residential class, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Maryland's existing demand response comes primarily from residential DLC and Other DR programs for Large C&I customers. The large impacts for Other DR are a due to participation in PJM demand response programs.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. The rest of the increase in potential comes from dynamic pricing without enabling technology. Overall, the incremental increase relative to the BAU scenario is small because the state is already achieving significant impacts from non-pricing programs.

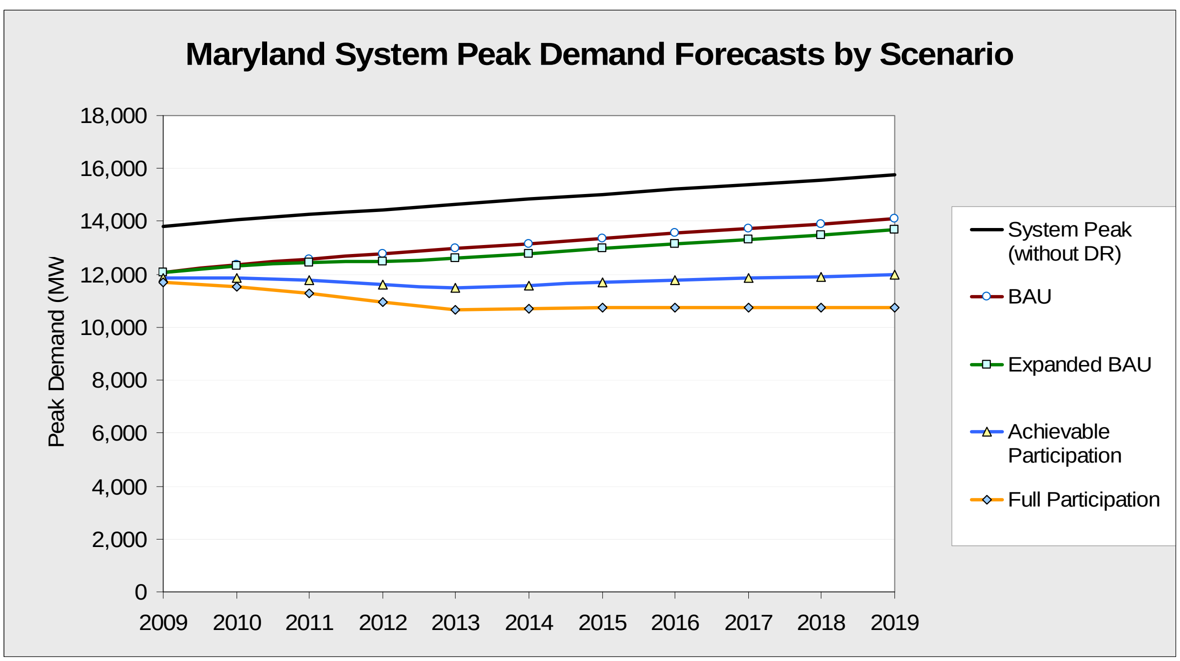
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Growth in dynamic pricing with enabling technologies occurs for all C&I customers except for Medium C&I, as this is the only class for which the option is not cost effective.

Full Participation: Relative to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Maryland, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	0	0.0%	9	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	502	3.2%	13	0.1%	9	0.1%	1,143	7.3%	1,667	10.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	54	0.3%	1	0.0%	2	0.0%	8	0.1%	65	0.4%
Automated/Direct Load Control	502	3.2%	20	0.1%	5	0.0%	0	0.0%	528	3.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	556	3.5%	21	0.1%	19	0.1%	1,485	9.4%	2,081	13.2%
Achievable Participation										
Pricing with Technology	933	5.9%	173	1.1%	0	0.0%	50	0.3%	1,156	7.3%
Pricing without Technology	459	2.9%	10	0.1%	34	0.2%	91	0.6%	593	3.8%
Automated/Direct Load Control	502	3.2%	13	0.1%	2	0.0%	0	0.0%	517	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	1,894	12.0%	196	1.2%	47	0.3%	1,618	10.3%	3,755	23.8%
Full Participation										
Pricing with Technology	2,182	13.9%	405	2.6%	0	0.0%	146	0.9%	2,733	17.4%
Pricing without Technology	76	0.5%	5	0.0%	56	0.4%	118	0.7%	255	1.6%
Automated/Direct Load Control	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	2,760	17.5%	423	2.7%	68	0.4%	1,741	11.1%	4,991	31.7%



Massachusetts State Profile

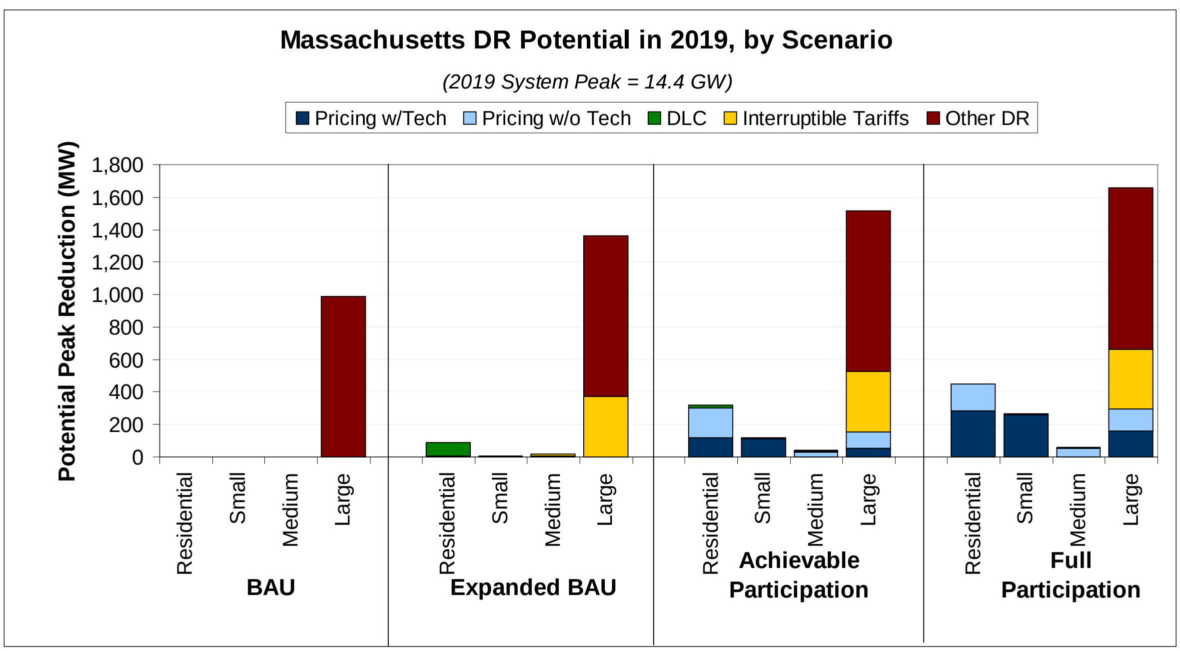
Key drivers of the Massachusetts demand response potential estimate include: significantly lower-than-average residential CAC saturation of 12.7 percent, a customer mix that has an above average share of peak demand in the Large C&I class, a moderate amount of existing Other DR, and an AMI deployment schedule that is anticipated to be slower-than-average. Enabling technologies are cost effective for all classes except the Medium C&I class; DLC technology is cost effective across all customer classes.

BAU: Massachusetts' existing demand response comes entirely from the Large C&I class, which currently has significant enrollment in Other DR, particularly ISO-NE programs.

Expanded BAU: The Expanded BAU scenario includes the addition of an interruptible tariff for the Large C&I class, which can have significant impact due to the high share of Large C&I peak demand in the customer mix. DLC program participation by the Residential class also contributes to Massachusetts' Expanded BAU scenario.

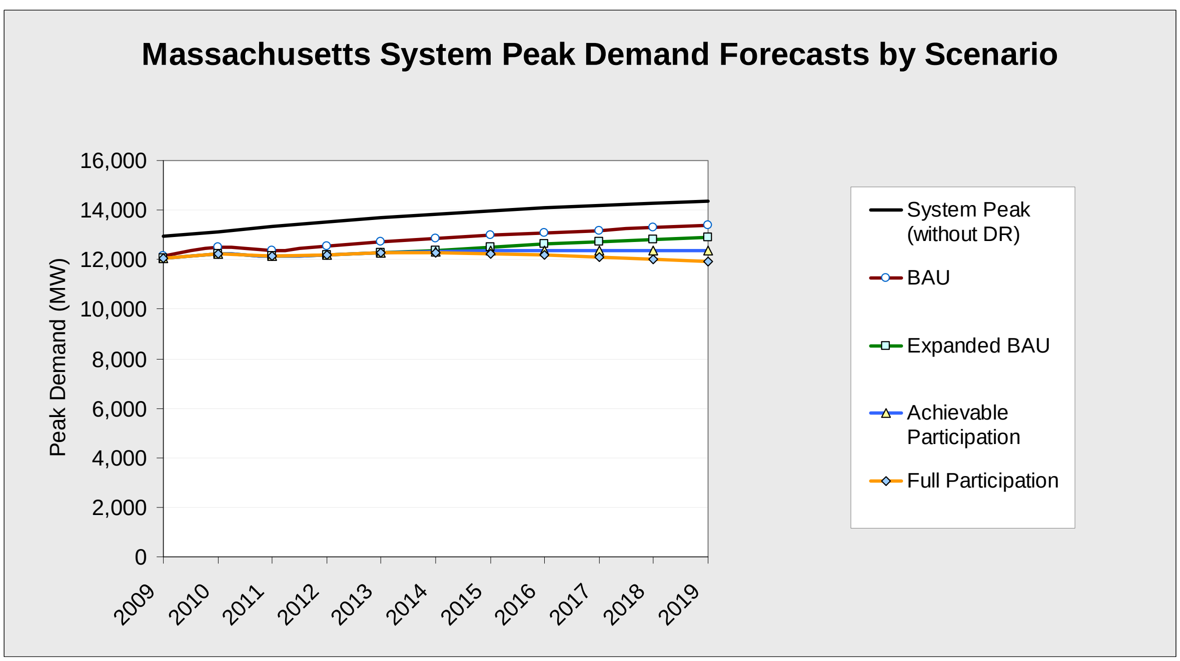
Achievable Participation: Low CAC saturation in the residential sector limits dynamic pricing potential. Furthermore, with enabling technology only cost effective in the Small and Large C&I classes, Other DR in the Large C&I class is still the dominant source of demand response potential.

Full Participation: The Full participation scenario is similar to the Achievable Participation scenario, with incremental increases in dynamic pricing potential. The relatively low incremental difference between the BAU scenario and the Full Participation scenario is driven primarily by low CAC saturation and limited cost-effectiveness for enabling technology.



Total Potential Peak Reduction from Demand Response in Massachusetts, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	0	0.0%	1	0.0%	0	0.0%	990	6.9%	991	6.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.0%	1	0.0%	1	0.0%	3	0.0%	8	0.1%
Automated/Direct Load Control	85	0.6%	7	0.0%	8	0.1%	0	0.0%	101	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	90	0.6%	8	0.1%	16	0.1%	1,364	9.5%	1,478	10.3%
Achievable Participation										
Pricing with Technology	121	0.8%	111	0.8%	0	0.0%	56	0.4%	288	2.0%
Pricing without Technology	179	1.2%	7	0.0%	31	0.2%	101	0.7%	319	2.2%
Automated/Direct Load Control	22	0.2%	2	0.0%	3	0.0%	0	0.0%	27	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	322	2.2%	120	0.8%	42	0.3%	1,518	10.6%	2,002	13.9%
Full Participation										
Pricing with Technology	283	2.0%	260	1.8%	0	0.0%	163	1.1%	706	4.9%
Pricing without Technology	169	1.2%	4	0.0%	52	0.4%	131	0.9%	357	2.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	452	3.1%	264	1.8%	60	0.4%	1,655	11.5%	2,432	16.9%



Michigan State Profile

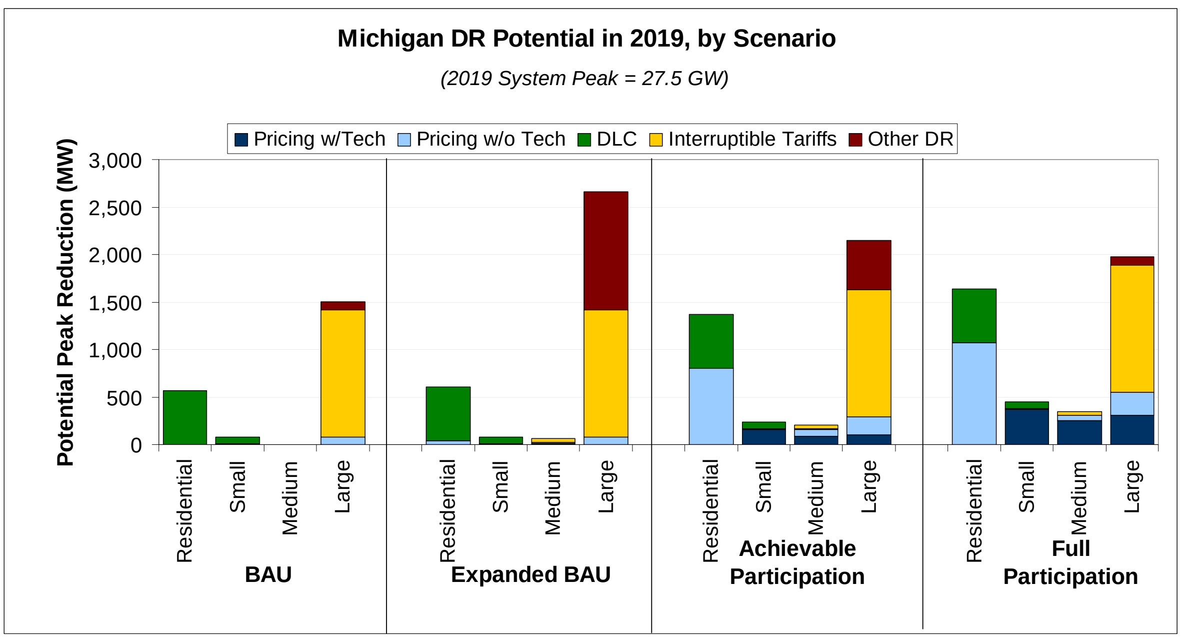
Key drivers of Michigan's demand response potential estimate include: above average residential CAC saturation of 57%, above average share of peak demand (37%) in the Large C&I classes, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the residential class. DLC is cost effective for all customer classes.

BAU: Michigan's existing demand response comes predominantly from interruptible tariffs for the Large C&I class and represents one of the largest interruptible loads in the country. Interruptible tariffs account for at least 30% of the total potential under all other scenarios. The state is also one of the few states that has a significant portion of price induced demand response.

Expanded BAU: Significant growth in Other DR is due to Michigan's above average share of Large C&I load. The rest of the impacts come from Pricing without technology and DLC for the other customer segments.

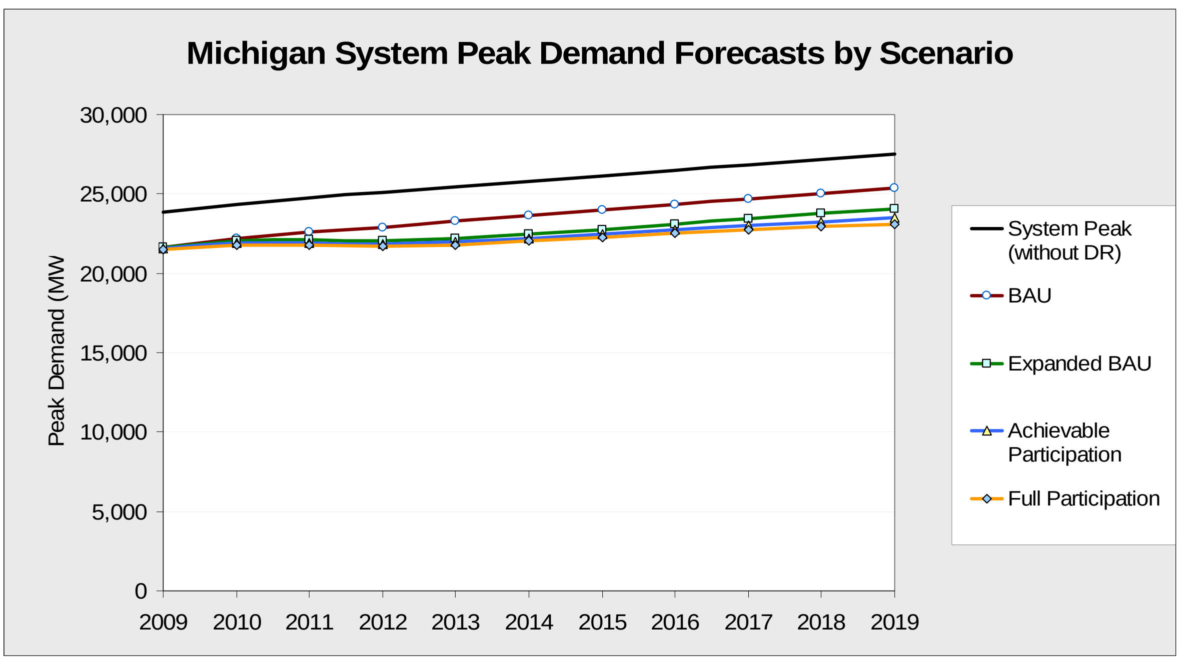
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for all classes except for the residential sector, contributes additional potential for the C&I customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing without enabling technologies for all customer classes. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in Michigan, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	6	0.0%	0	0.0%	77	0.3%	83	0.3%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	1,339	4.9%	1,341	4.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	570	2.1%	75	0.3%	2	0.0%	1,502	5.5%	2,149	7.8%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	37	0.1%	6	0.0%	7	0.0%	77	0.3%	127	0.5%
Automated/Direct Load Control	570	2.1%	69	0.3%	18	0.1%	0	0.0%	657	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,245	4.5%	1,245	4.5%
Total	607	2.2%	75	0.3%	67	0.2%	2,661	9.7%	3,409	12.4%
Achievable Participation										
Pricing with Technology	0	0.0%	160	0.6%	88	0.3%	105	0.4%	352	1.3%
Pricing without Technology	801	2.9%	10	0.0%	70	0.3%	190	0.7%	1,071	3.9%
Automated/Direct Load Control	570	2.1%	69	0.3%	7	0.0%	0	0.0%	647	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	516	1.9%	516	1.9%
Total	1,371	5.0%	238	0.9%	207	0.8%	2,149	7.8%	3,965	14.4%
Full Participation										
Pricing with Technology	0	0.0%	373	1.4%	256	0.9%	306	1.1%	935	3.4%
Pricing without Technology	1,068	3.9%	6	0.0%	48	0.2%	246	0.9%	1,368	5.0%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	1,638	6.0%	448	1.6%	345	1.3%	1,977	7.2%	4,409	16.0%



Minnesota State Profile

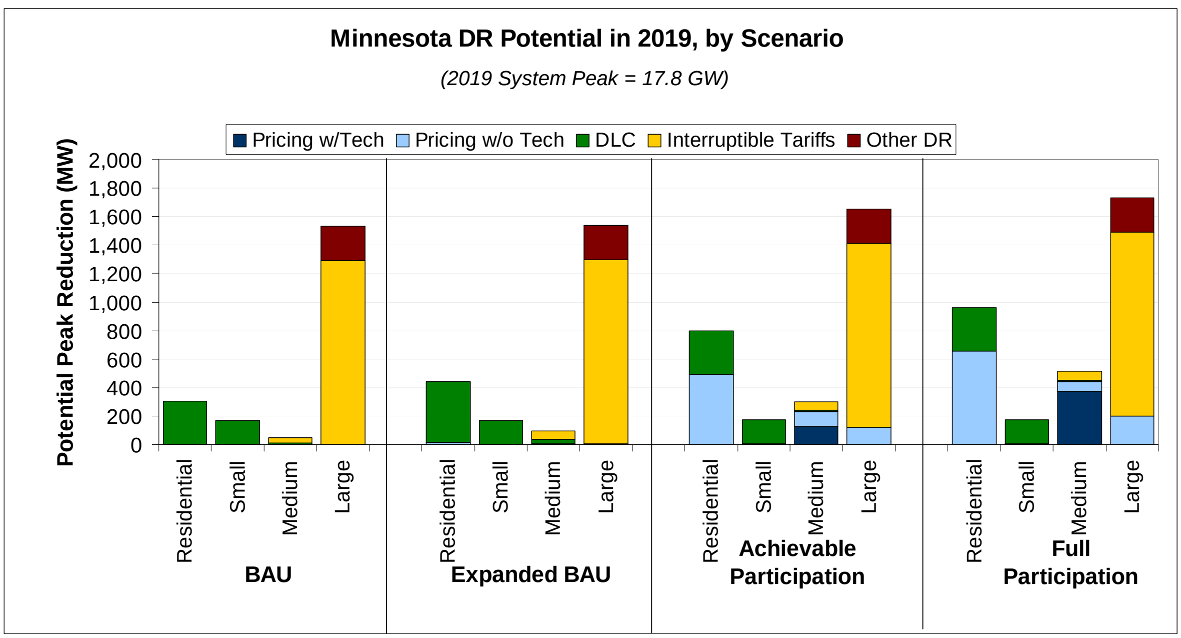
Key drivers of Minnesota's demand response potential estimate include: a substantial amount of existing demand response, above average share of peak demand (30%) in the Large C&I classes and a large residential base. Pricing with enabling technologies is not cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Minnesota's existing demand response comes primarily from interruptible tariffs and Other DR programs for Medium and Large C&I customers. The savings from interruptible tariffs account for at least 40% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states. The rest of the existing potential comes from direct load control programs for residential and Small and Medium C&I customers.

Expanded BAU: DLC and dynamic pricing without enabling technology account for the growth in potential. Since current participation levels in interruptible tariffs is substantially high, there is not much scope for growth in this program.

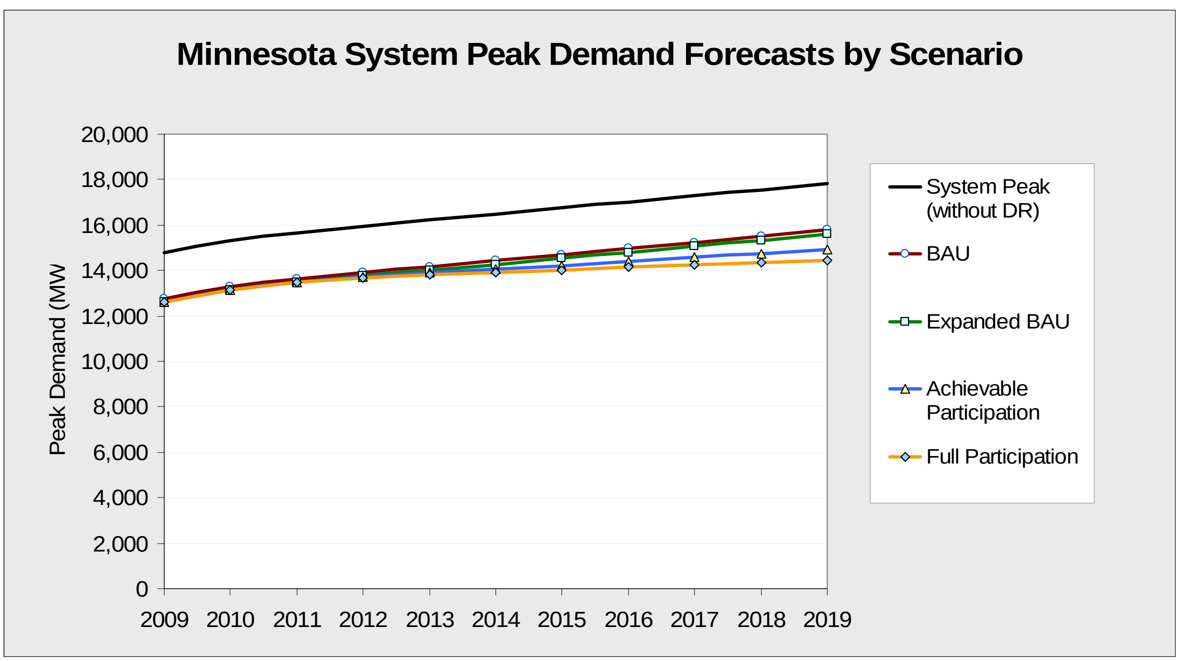
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for the Medium C&I class contributes additional savings.

Full Participation: Similar to Achievable Participation, the incremental impacts come from dynamic pricing.



Total Potential Peak Reduction from Demand Response in Minnesota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	1	0.0%	1	0.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	0.2%	1,290	7.2%	1,329	7.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	304	1.7%	170	1.0%	49	0.3%	1,533	8.6%	2,056	11.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	0	0.0%	7	0.0%	5	0.0%	27	0.2%
Automated/Direct Load Control	428	2.4%	170	1.0%	27	0.2%	0	0.0%	626	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	443	2.5%	170	1.0%	96	0.5%	1,537	8.6%	2,247	12.6%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	127	0.7%	0	0.0%	127	0.7%
Pricing without Technology	492	2.8%	3	0.0%	102	0.6%	121	0.7%	718	4.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	796	4.5%	173	1.0%	302	1.7%	1,653	9.3%	2,924	16.4%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	372	2.1%	0	0.0%	372	2.1%
Pricing without Technology	656	3.7%	4	0.0%	69	0.4%	202	1.1%	931	5.2%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	959	5.4%	174	1.0%	514	2.9%	1,734	9.7%	3,381	19.0%



Mississippi State Profile

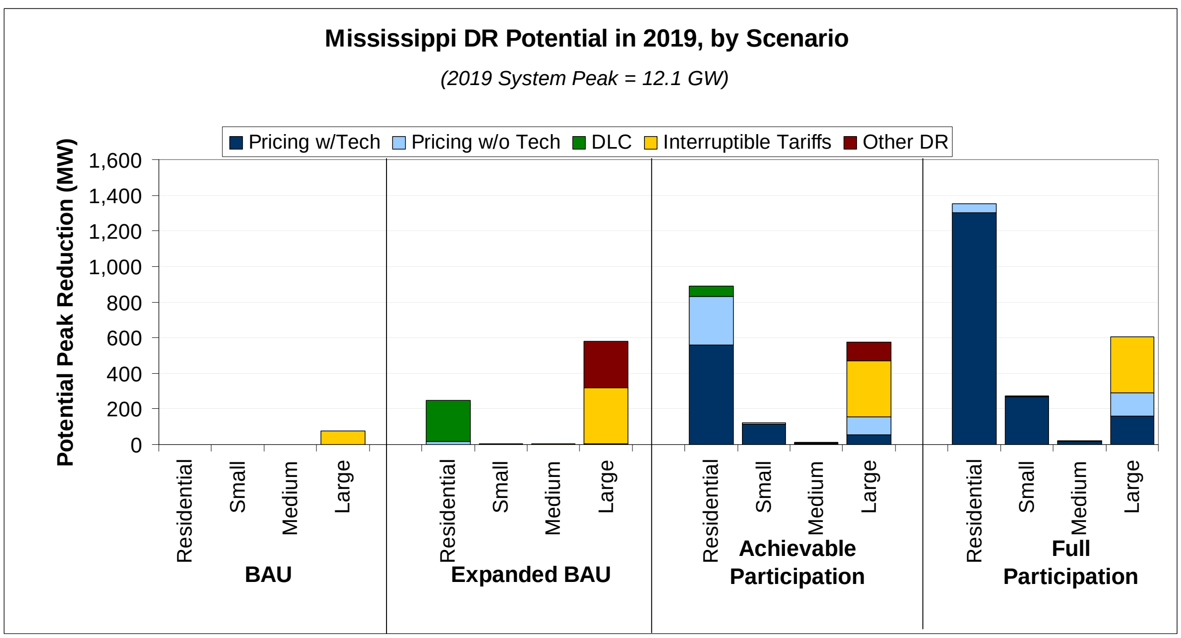
Key drivers of Mississippi's demand response potential estimate include: above average residential CAC saturation of 75% and a customer mix that has an above average share of peak demand in the residential and Large C&I classes (47% and 30%, respectively). Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Mississippi's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential class. Growth in the existing interruptible tariffs accounts for the remaining portion.

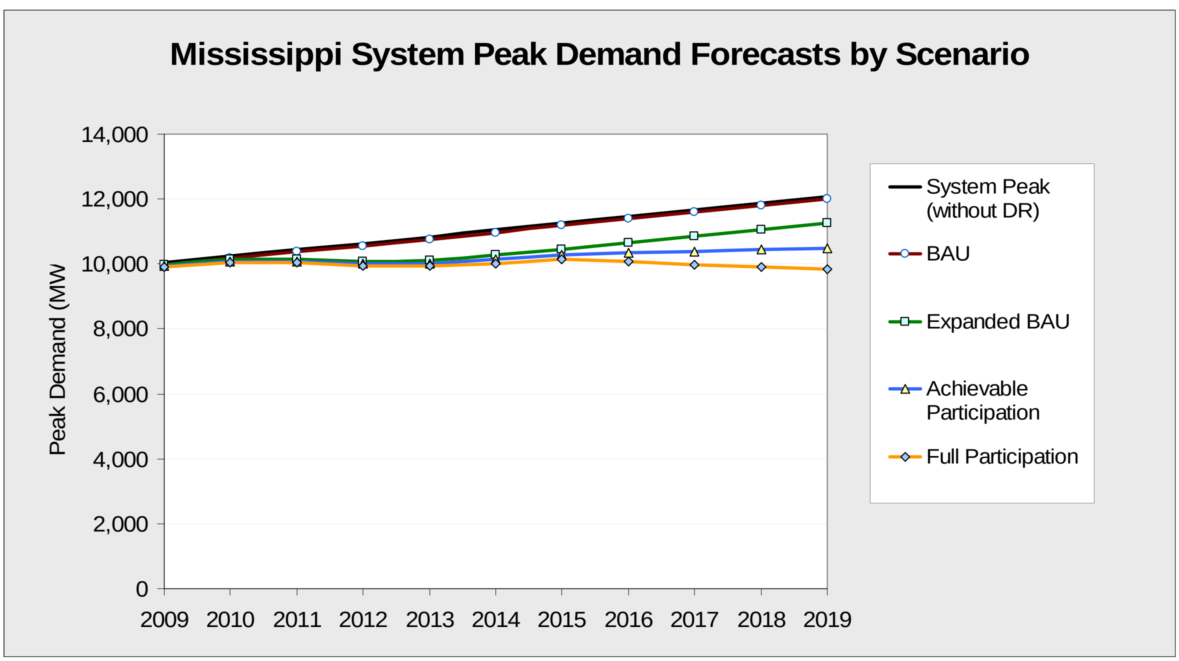
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents over 75% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Mississippi, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	75	0.6%	75	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	75	0.6%	75	0.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	17	0.1%	0	0.0%	0	0.0%	5	0.0%	22	0.2%
Automated/Direct Load Control	230	1.9%	5	0.0%	1	0.0%	0	0.0%	236	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	247	2.0%	5	0.0%	3	0.0%	581	4.8%	836	6.9%
Achievable Participation										
Pricing with Technology	557	4.6%	114	0.9%	6	0.0%	55	0.5%	732	6.1%
Pricing without Technology	277	2.3%	6	0.1%	4	0.0%	100	0.8%	387	3.2%
Automated/Direct Load Control	59	0.5%	1	0.0%	0	0.0%	0	0.0%	60	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	0.9%	107	0.9%
Total	892	7.4%	122	1.0%	11	0.1%	577	4.8%	1,602	13.3%
Full Participation										
Pricing with Technology	1,303	10.8%	268	2.2%	17	0.1%	161	1.3%	1,748	14.5%
Pricing without Technology	49	0.4%	3	0.0%	2	0.0%	130	1.1%	183	1.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,351	11.2%	271	2.2%	20	0.2%	605	5.0%	2,247	18.6%



Missouri State Profile

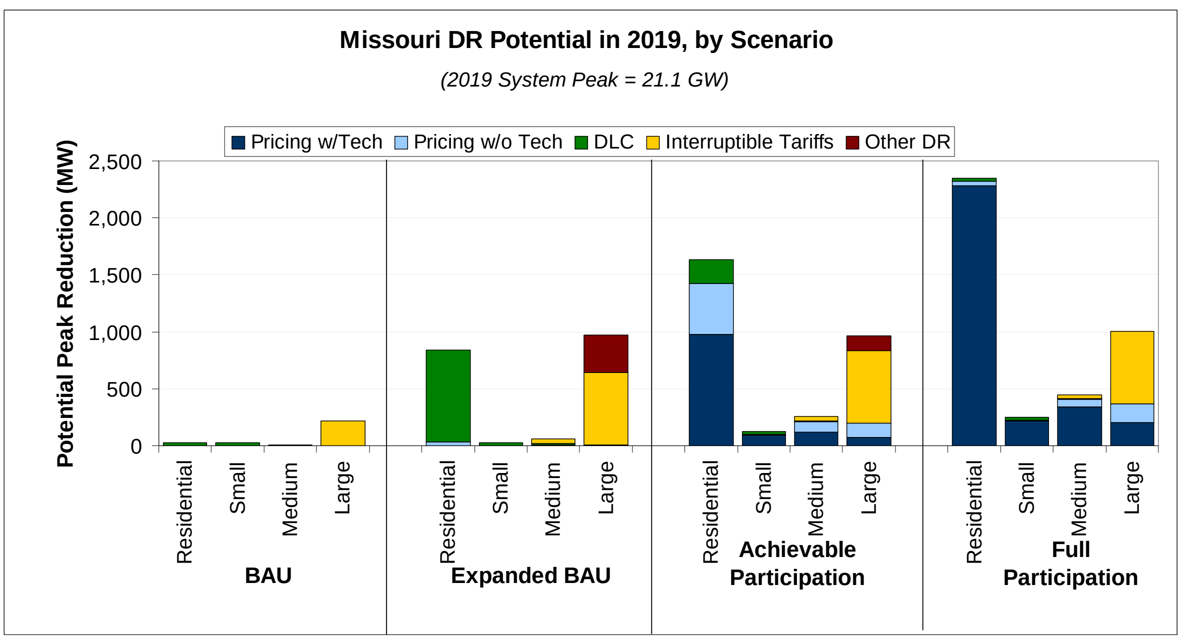
Key drivers of Missouri's demand response potential estimate include: above average residential CAC saturation of 87%, above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes.

BAU: Missouri's existing demand response comes predominantly from interruptible tariffs for the Large C&I class. Direct load control programs for the other classes account for the remainder.

Expanded BAU: Significant growth in DLC impacts is due to Missouri's above average share of residential load. Growth for the Large C&I class in Other DR and interruptible tariffs account for the remaining portion.

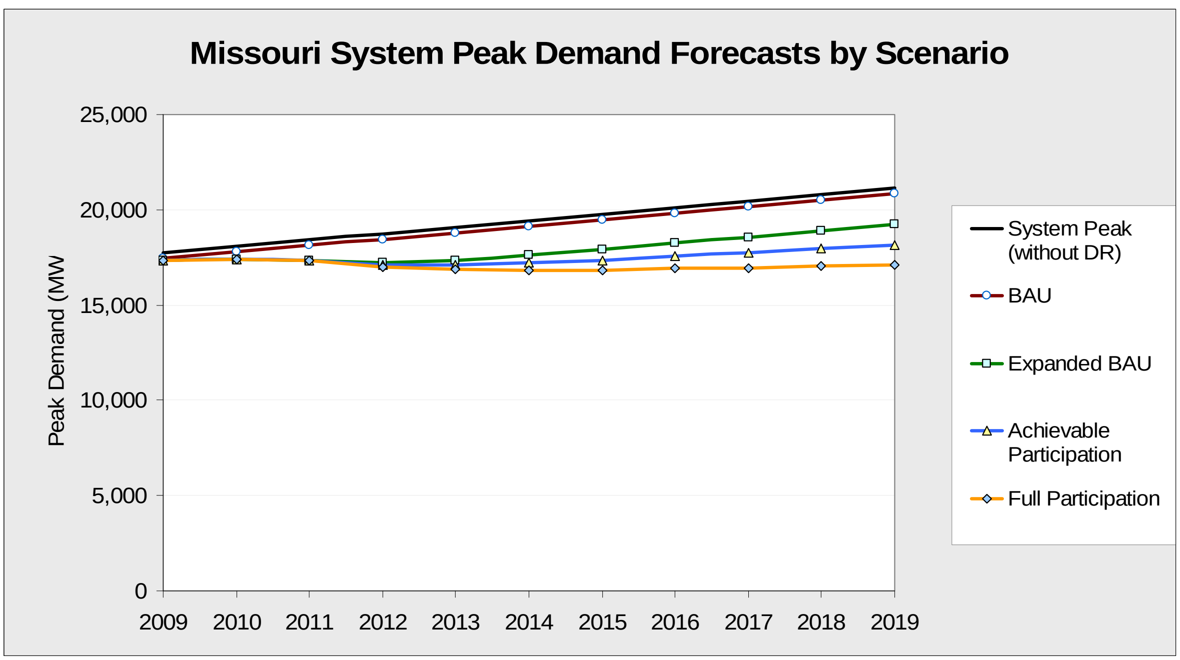
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing with enabling impacts which is cost effective for all classes. Dynamic pricing without enabling technology contributes additional potential for all customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing with enabling option for all customer classes. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Missouri, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	219	1.0%	219	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	29	0.1%	29	0.1%	5	0.0%	219	1.0%	282	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	0	0.0%	6	0.0%	6	0.0%	43	0.2%
Automated/Direct Load Control	809	3.8%	29	0.1%	13	0.1%	0	0.0%	851	4.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	328	1.6%	328	1.6%
Total	840	4.0%	29	0.1%	58	0.3%	972	4.6%	1,899	9.0%
Achievable Participation										
Pricing with Technology	977	4.6%	93	0.4%	117	0.6%	69	0.3%	1,255	5.9%
Pricing without Technology	450	2.1%	6	0.0%	93	0.4%	126	0.6%	674	3.2%
Automated/Direct Load Control	207	1.0%	29	0.1%	5	0.0%	0	0.0%	241	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	134	0.6%	134	0.6%
Total	1,634	7.7%	127	0.6%	254	1.2%	966	4.6%	2,982	14.1%
Full Participation										
Pricing with Technology	2,285	10.8%	217	1.0%	341	1.6%	202	1.0%	3,045	14.4%
Pricing without Technology	38	0.2%	3	0.0%	64	0.3%	163	0.8%	268	1.3%
Automated/Direct Load Control	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,352	11.1%	249	1.2%	449	2.1%	1,002	4.7%	4,052	19.2%



Montana State Profile

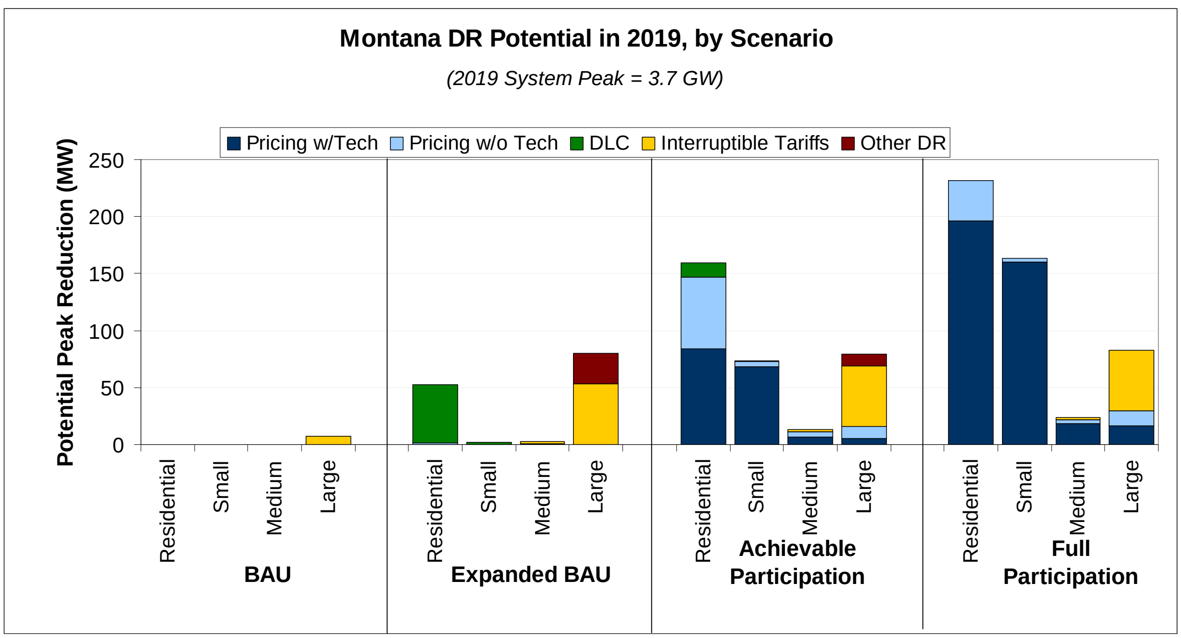
Key drivers of Montana's demand response potential estimate include: a higher than average share of peak demand (53%) in the Small C&I class and a moderate CAC saturation of 42%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Montana's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential and Small C&I classes. Growth in the interruptible tariffs accounts for the remaining portion.

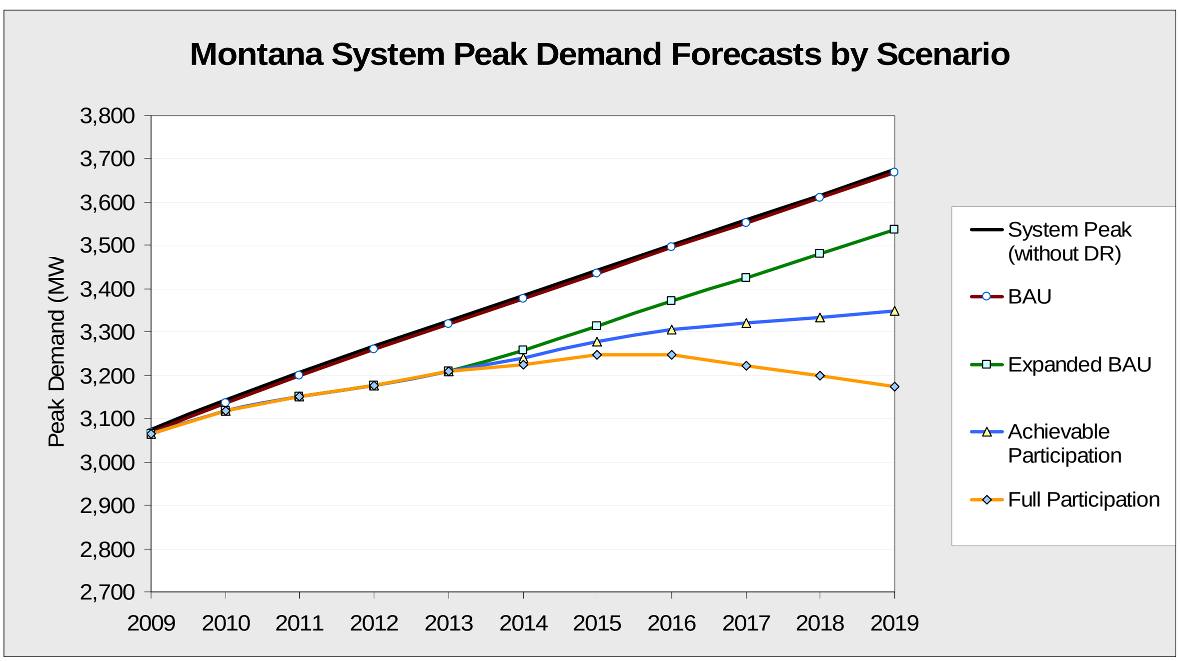
Achievable Participation: Dynamic pricing with enabling impacts accounts for over 50% of the increase in potential, with 20% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents almost 80% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Montana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	7	0.2%	7	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	7	0.2%	7	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.1%
Automated/Direct Load Control	51	1.4%	2	0.1%	0	0.0%	0	0.0%	53	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	27	0.7%	27	0.7%
Total	52	1.4%	2	0.1%	3	0.1%	80	2.2%	137	3.7%
Achievable Participation										
Pricing with Technology	84	2.3%	69	1.9%	6	0.2%	6	0.2%	164	4.5%
Pricing without Technology	63	1.7%	5	0.1%	5	0.1%	10	0.3%	82	2.2%
Automated/Direct Load Control	13	0.3%	1	0.0%	0	0.0%	0	0.0%	14	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.3%	11	0.3%
Total	160	4.3%	74	2.0%	13	0.4%	80	2.2%	326	8.9%
Full Participation										
Pricing with Technology	196	5.3%	160	4.4%	18	0.5%	16	0.4%	391	10.7%
Pricing without Technology	35	1.0%	3	0.1%	3	0.1%	13	0.4%	55	1.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	232	6.3%	163	4.4%	24	0.6%	83	2.2%	501	13.6%



Nebraska State Profile

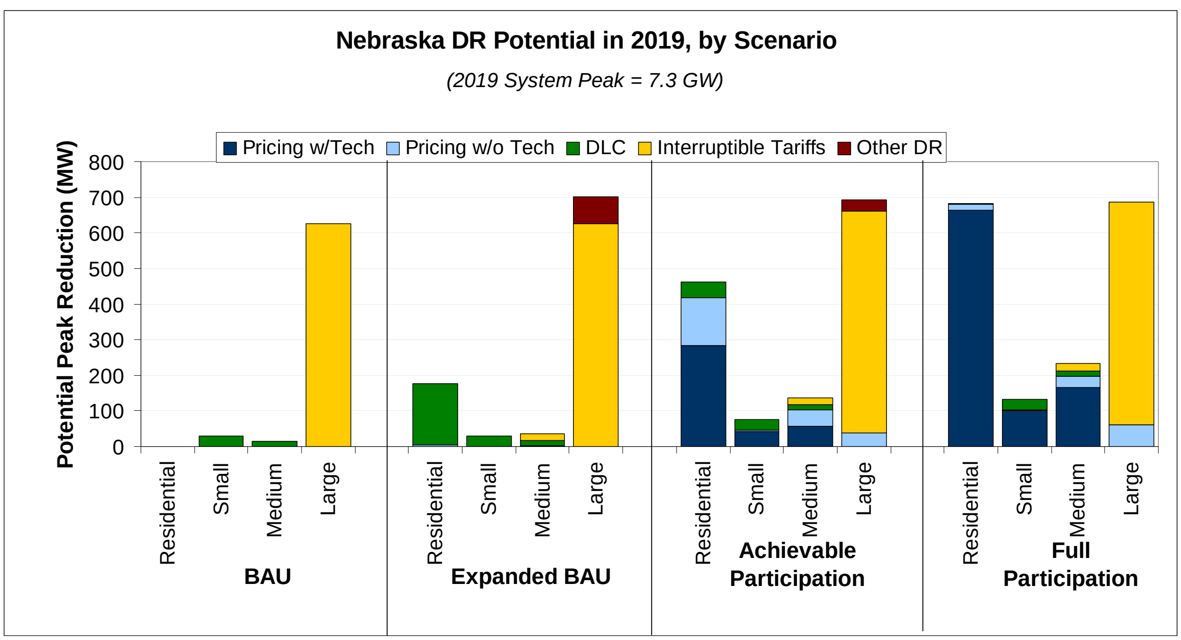
Key drivers of Nebraska's demand response potential estimate include: higher-than-average residential CAC saturation of 83%, a customer mix that has a moderate share of peak demand in the residential and Medium C&I classes (40% and 27%, respectively) and a substantial amount of existing demand response. Pricing with enabling technologies are cost effective for all customer classes, except for the Large C&I class. DLC is cost effective for all customer classes.

BAU: Nebraska's existing demand response comes predominantly from interruptible tariffs for Large C&I customers. The impacts from this option represent at least 30% of the total impacts under all scenarios. DLC for Small & Medium C&I accounts for the remaining portion of existing demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR for the Large C&I class and DLC for the residential class.

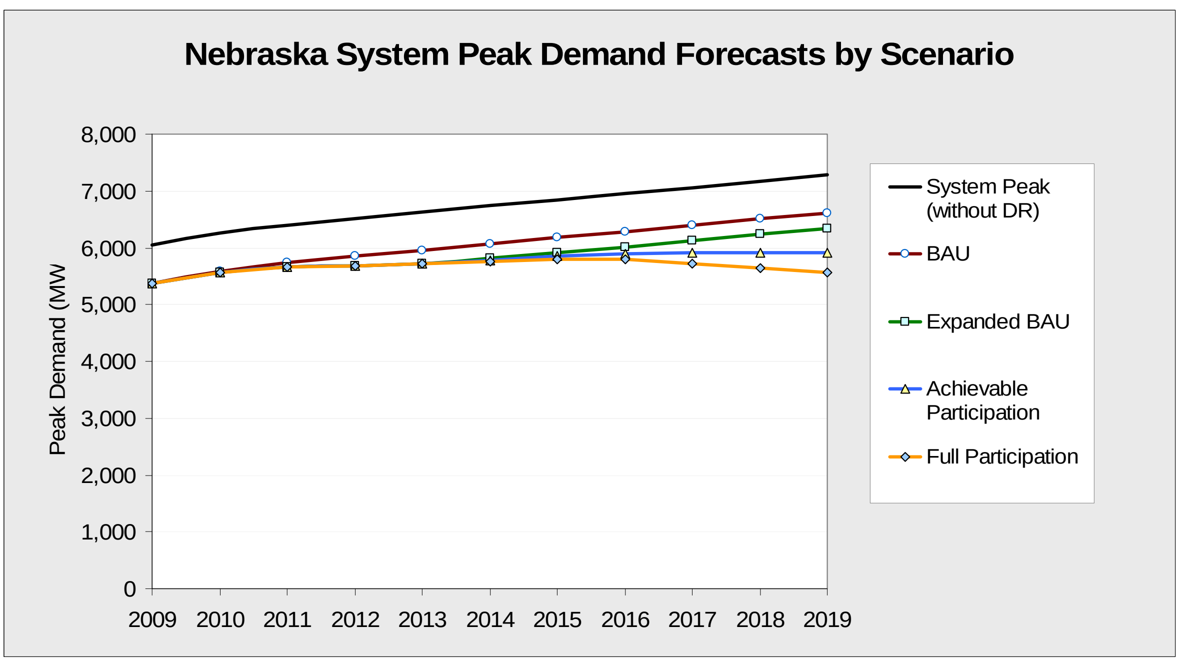
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a moderate share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for the Large C&I customers. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Nebraska, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	625	8.6%	625	8.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1	0.0%	30	0.4%	15	0.2%	625	8.6%	671	9.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	1	0.0%	1	0.0%	6	0.1%
Automated/Direct Load Control	172	2.4%	30	0.4%	15	0.2%	0	0.0%	217	3.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	1.0%	75	1.0%
Total	176	2.4%	30	0.4%	35	0.5%	701	9.6%	943	12.9%
Achievable Participation										
Pricing with Technology	284	3.9%	43	0.6%	57	0.8%	0	0.0%	384	5.3%
Pricing without Technology	135	1.9%	3	0.0%	46	0.6%	37	0.5%	220	3.0%
Automated/Direct Load Control	44	0.6%	30	0.4%	15	0.2%	0	0.0%	89	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.4%	30	0.4%
Total	462	6.3%	76	1.0%	137	1.9%	693	9.5%	1,367	18.8%
Full Participation										
Pricing with Technology	664	9.1%	100	1.4%	167	2.3%	0	0.0%	931	12.8%
Pricing without Technology	17	0.2%	2	0.0%	31	0.4%	61	0.8%	111	1.5%
Automated/Direct Load Control	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	681	9.3%	132	1.8%	232	3.2%	687	9.4%	1,732	23.8%



Nevada State Profile

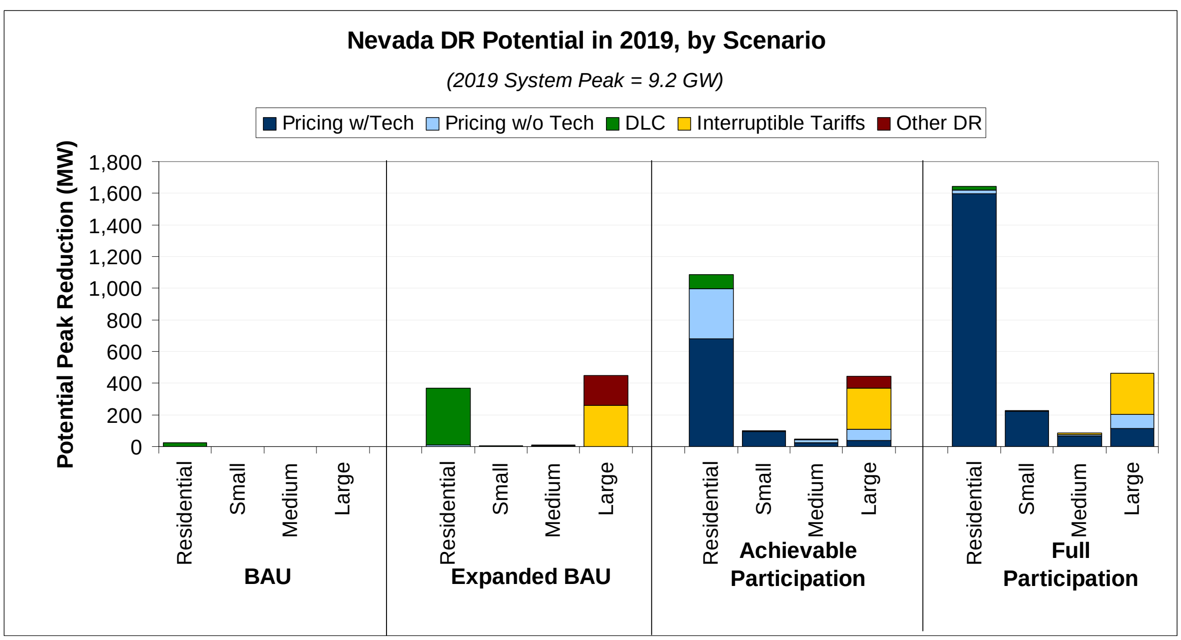
Key drivers of Nevada's demand response potential estimate include: a very high residential CAC saturation of 87%, and a customer mix that has an above average share of peak demand in the residential sector. The rate of AMI deployment is likely to be at a lower-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Control of residential air-conditioning load is the key driver of demand response potential in Nevada.

BAU: Nevada's existing demand response comes primarily from residential DLC programs. However, current participation levels are low and there exists scope for significant growth in potential.

Expanded BAU: Growth in demand response impacts is driven primarily through substantial expansion in residential DLC programs due to very high levels of CAC saturation in the state. Impacts also grow due to large C&I participation in 'Interruptible' and 'Other DR' programs.

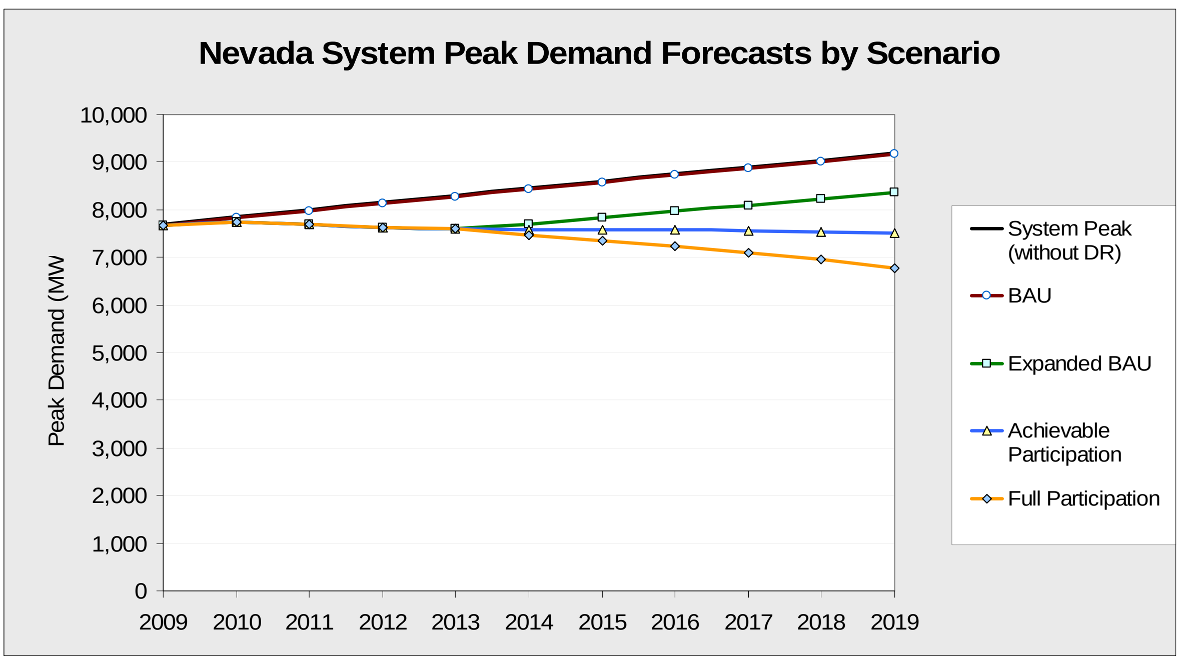
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of residential load leads to substantial increase in impacts. The impacts are dominated by pricing with enabling technologies. Small and medium C&I potential from pricing programs increase. Large C&I potential is lower than in the Achievable scenario. This is because customers choose dynamic pricing over 'Other DR' programs, leading to a lower level of impacts caused by smaller per-customer impacts from pricing programs relative to 'Other DR'.



Total Potential Peak Reduction from Demand Response in Nevada, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	12	0.1%	0	0.0%	1	0.0%	2	0.0%	14	0.2%
Automated/Direct Load Control	356	3.9%	4	0.0%	2	0.0%	0	0.0%	363	3.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	186	2.0%	186	2.0%
Total	368	4.0%	4	0.0%	10	0.1%	447	4.9%	830	9.0%
Achievable Participation										
Pricing with Technology	682	7.4%	94	1.0%	23	0.2%	39	0.4%	838	9.1%
Pricing without Technology	313	3.4%	6	0.1%	17	0.2%	71	0.8%	407	4.4%
Automated/Direct Load Control	90	1.0%	1	0.0%	1	0.0%	0	0.0%	92	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	0.8%	75	0.8%
Total	1,085	11.8%	102	1.1%	49	0.5%	444	4.8%	1,679	18.3%
Full Participation										
Pricing with Technology	1,596	17.4%	221	2.4%	67	0.7%	113	1.2%	1,996	21.7%
Pricing without Technology	25	0.3%	4	0.0%	11	0.1%	91	1.0%	131	1.4%
Automated/Direct Load Control	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,642	17.9%	225	2.4%	85	0.9%	464	5.1%	2,416	26.3%



New Hampshire State Profile

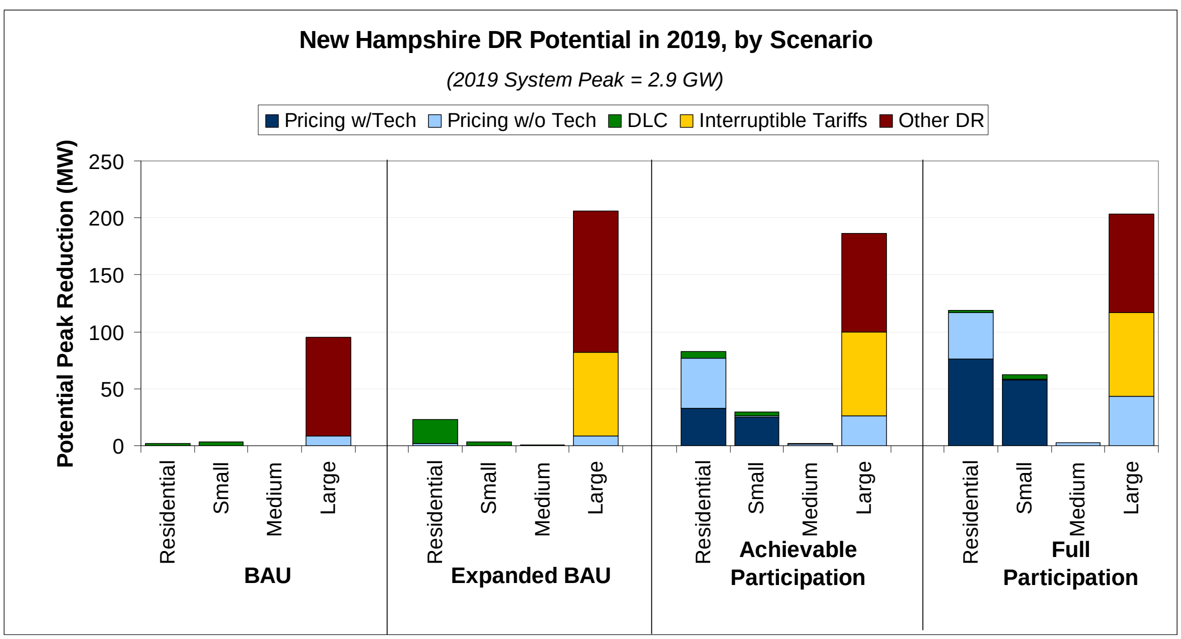
Key drivers of New Hampshire's demand response potential estimate include: a higher than average share of large C&I peak load (33%) and large base of existing load participation in the ISO-NE market. It has a lower than national average residential CAC saturation at 13%, thereby limiting load reduction potential from DLC programs. Dynamic pricing with enabling technology is cost-effective only for residential and small C&I customers. DLC is cost-effective for all customer classes.

BAU: New Hampshire's existing demand response is primarily derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Potential for growth in 'Other DR' programs is limited due to current high participation levels. Load reductions from residential DLC programs also grow in this scenario.

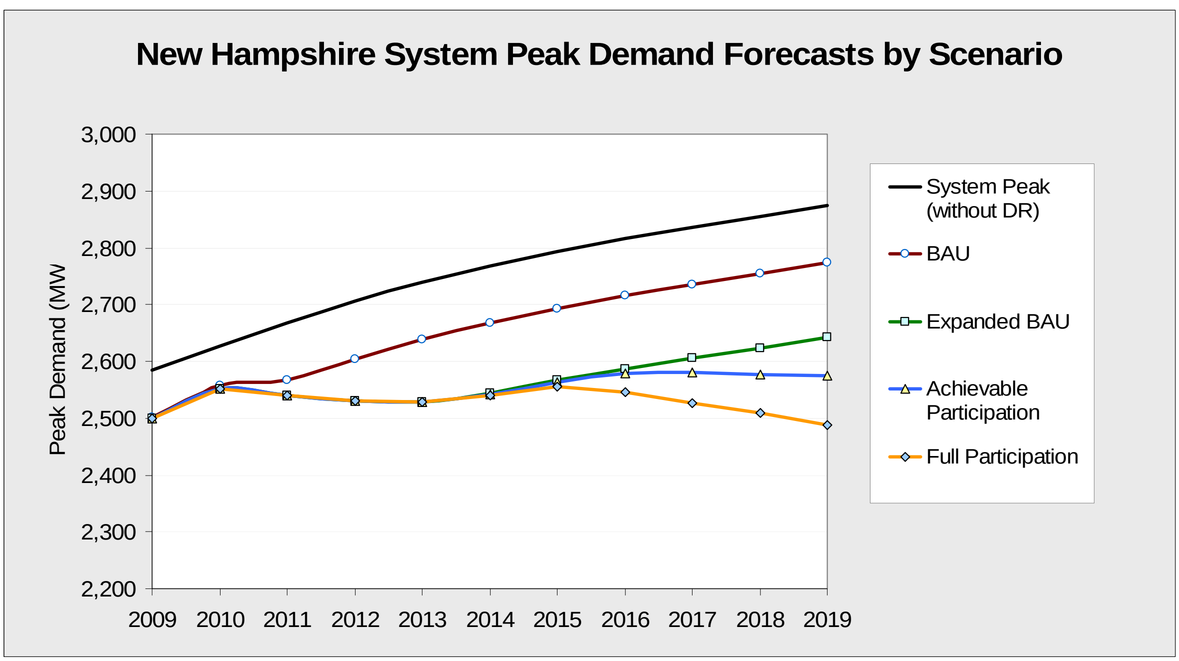
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived through 'pricing without technology' option, primarily from residential and large C&I customers. Growth in impacts from 'pricing with technology' comes from both residential and small C&I customers. 'Other DR' program potential remains at current high levels.

Full Participation: Similar to the Achievable Participation scenario, increase in residential and small C&I customer participation in pricing options drive increase in impacts. Contribution from 'Other DR' and Interruptible programs continues to dominate for large C&I customers.



Total Potential Peak Reduction from Demand Response in New Hampshire, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	9	0.3%	9	0.3%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	2	0.1%	3	0.1%	0	0.0%	95	3.3%	101	3.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	9	0.3%	11	0.4%
Automated/Direct Load Control	21	0.7%	3	0.1%	0	0.0%	0	0.0%	24	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	124	4.3%	124	4.3%
Total	23	0.8%	3	0.1%	1	0.0%	206	7.2%	233	8.1%
Achievable Participation										
Pricing with Technology	32	1.1%	25	0.9%	0	0.0%	0	0.0%	57	2.0%
Pricing without Technology	45	1.6%	2	0.1%	2	0.1%	26	0.9%	74	2.6%
Automated/Direct Load Control	5	0.2%	3	0.1%	0	0.0%	0	0.0%	9	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	82	2.9%	30	1.0%	2	0.1%	186	6.5%	300	10.4%
Full Participation										
Pricing with Technology	76	2.6%	58	2.0%	0	0.0%	0	0.0%	134	4.7%
Pricing without Technology	41	1.4%	1	0.0%	3	0.1%	43	1.5%	88	3.0%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	119	4.1%	62	2.2%	3	0.1%	203	7.1%	387	13.5%



New Jersey State Profile

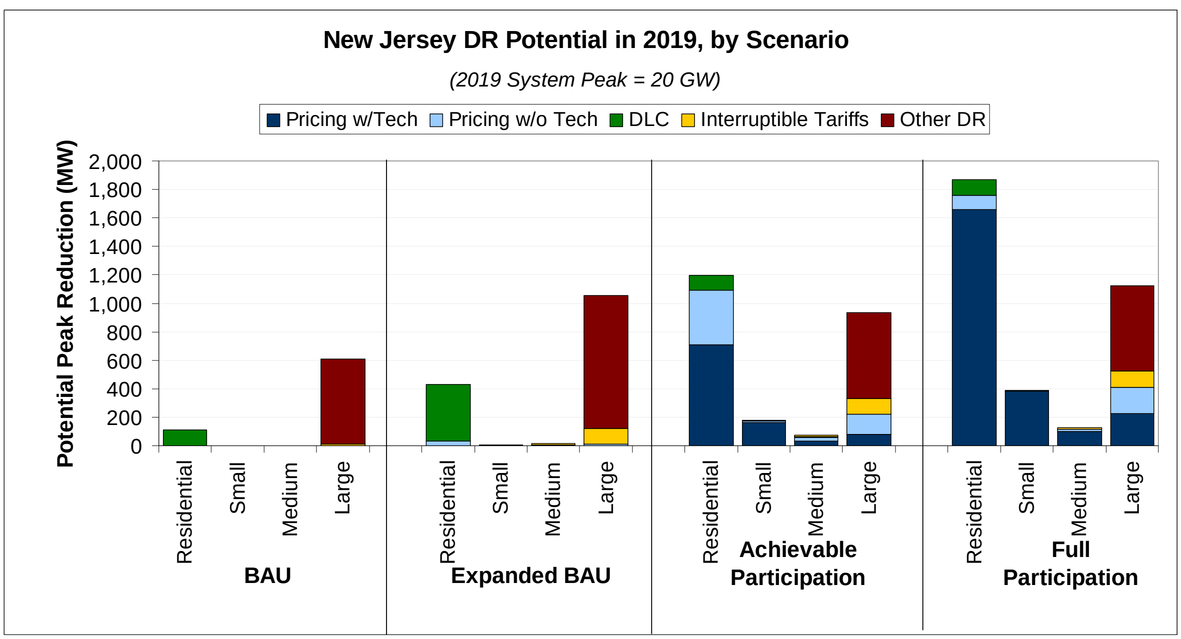
Key drivers of New Jersey's demand response potential estimate include: high levels of large C&I load participation in the PJM market, a customer mix with almost 48% of the load from residential customers and 26% of the load from large C&I customers, and the potential to deploy AMI at a faster-than-average rate. CAC saturation is at a moderate level of 55%. 'Pricing with technology' is cost-effective for all customer classes. DLC is also cost effective for all customer classes in the state.

BAU: New Jersey's existing demand response comes primarily from large C&I load participation in the PJM market. The remaining comes from residential DLC programs.

Expanded BAU: Increase in impacts for this scenario is primarily due to expansion in residential DLC programs and Interruptible programs for large C&I customers, driven by large share in load for these two customer classes. Also, the potential associated with large C&I participation in 'Other DR' programs grows.

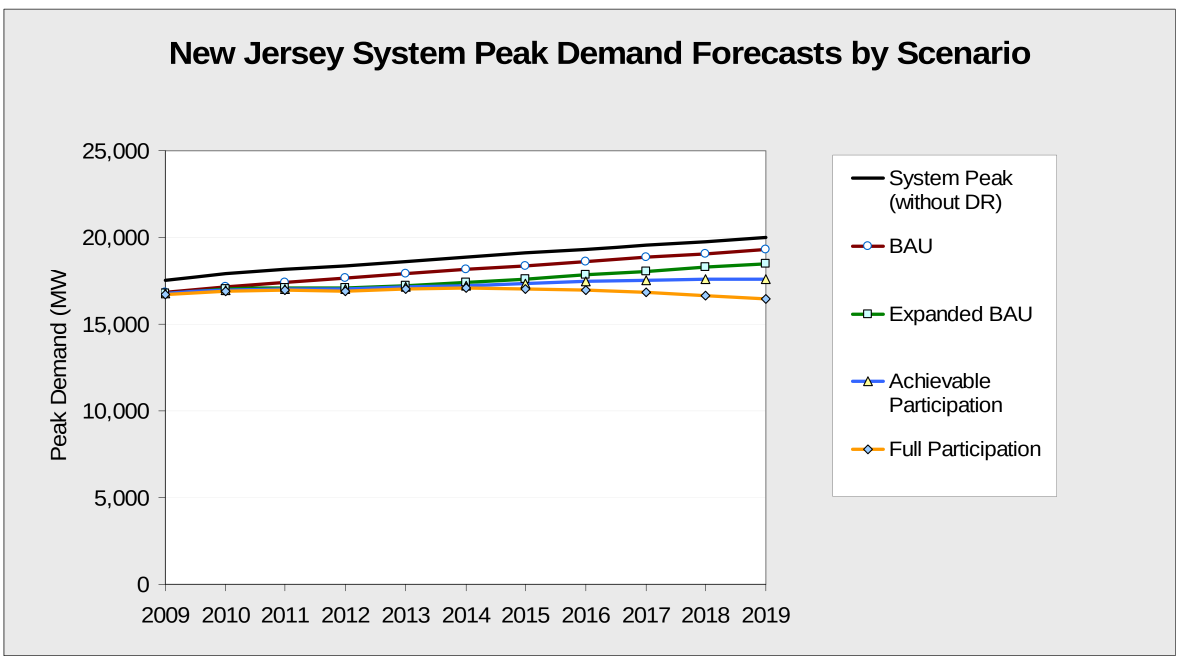
Achievable Participation: A high share of residential load in the total drives a substantial increase in impacts for residential customers through participation in pricing programs. In this scenario, impacts from residential DLC go back to current levels as customers choose pricing over DLC. For C&I customers, additional load reduction is obtained through pricing programs.

Full Participation: Similar to the Achievable Participation scenario, high impacts in this scenario are largely driven by a high level of residential load participating in pricing programs. Also, load reduction from C&I customers participating in pricing programs increases. Large C&I load participation in 'Other DR' programs continues at current high participation levels.



Total Potential Peak Reduction from Demand Response in New Jersey, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	108	0.5%	0	0.0%	0	0.0%	609	3.0%	717	3.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	29	0.1%	1	0.0%	2	0.0%	9	0.0%	41	0.2%
Automated/Direct Load Control	401	2.0%	7	0.0%	3	0.0%	0	0.0%	411	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	933	4.7%	933	4.7%
Total	430	2.2%	8	0.0%	17	0.1%	1,054	5.3%	1,508	7.5%
Achievable Participation										
Pricing with Technology	709	3.5%	164	0.8%	34	0.2%	78	0.4%	985	4.9%
Pricing without Technology	381	1.9%	10	0.1%	26	0.1%	142	0.7%	559	2.8%
Automated/Direct Load Control	108	0.5%	2	0.0%	1	0.0%	0	0.0%	111	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,198	6.0%	176	0.9%	73	0.4%	932	4.7%	2,379	11.9%
Full Participation										
Pricing with Technology	1,659	8.3%	384	1.9%	99	0.5%	227	1.1%	2,369	11.9%
Pricing without Technology	100	0.5%	6	0.0%	17	0.1%	183	0.9%	307	1.5%
Automated/Direct Load Control	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,867	9.3%	390	2.0%	127	0.6%	1,124	5.6%	3,508	17.5%



New Mexico State Profile

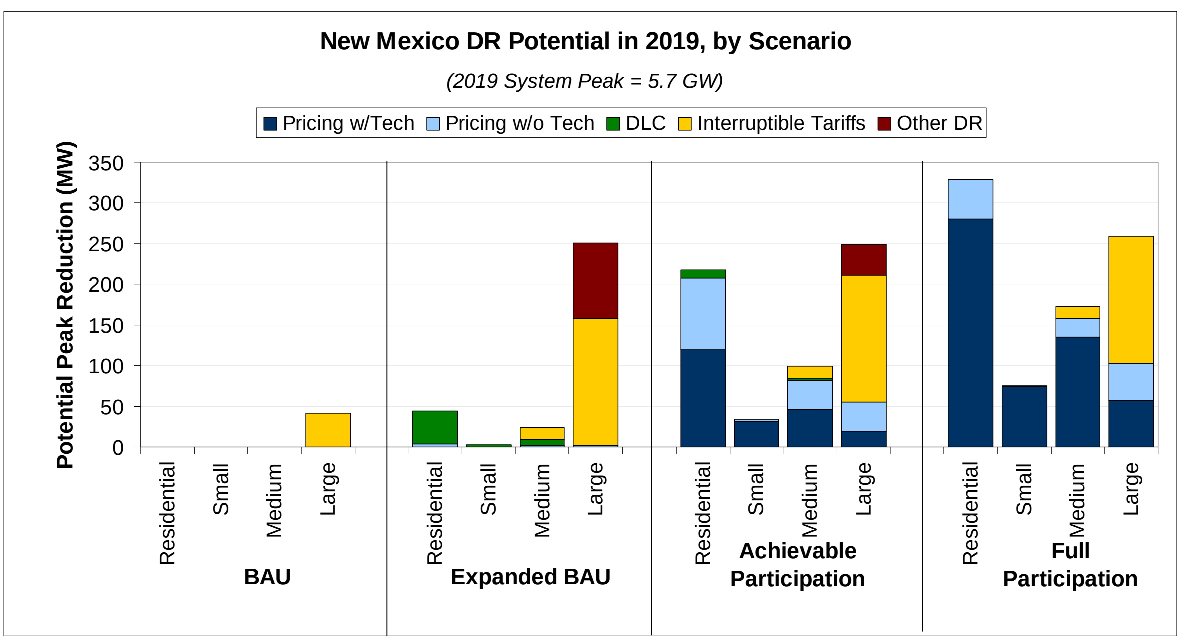
Key drivers of New Mexico's demand response potential estimate include: a customer mix that has an above average share of peak demand for medium C&I customers (50%), and a large share of residential (86%) in the total number of customer accounts. New Mexico has a low level of existing demand response with significant potential for growth across all rate classes. Dynamic pricing with enabling technology is cost-effective for all customer classes. Also, DLC is cost effective for all customer classes.

BAU: The state's existing demand response comes primarily from large C&I participation in Interruptible programs.

Expanded BAU: Growth in demand response potential under this scenario is derived through residential participation in DLC programs, and large C&I load participation in Interruptible and 'Other DR' programs. The potential for expansion is significant, given the low level of existing demand response.

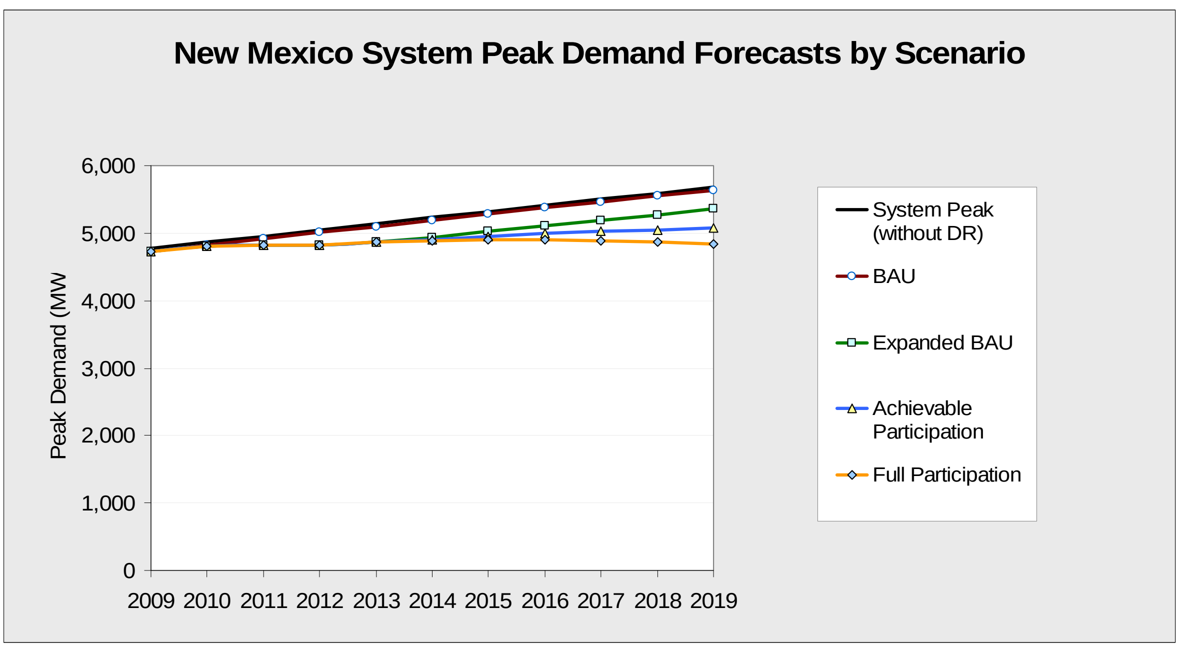
Achievable Participation: The potential increase in this scenario is primarily realized through residential pricing programs. The increase in impacts from the residential class is significant, given its high share in the total account population. Load reduction potential from C&I customers grow due to increased participation in pricing programs. Some of the large C&I customers participating in 'Other DR' programs choose to participate in the pricing programs.

Full Participation: Similar to the Achievable Participation scenario, a very high share of residential accounts in the total number of customer accounts drive increase in impacts from residential pricing programs. For the small and medium C&I classes, impacts are dominated by pricing with enabling technology. However, for the large C&I customers, impacts are dominated by participation in Interruptible programs.



Total Potential Peak Reduction from Demand Response in New Mexico, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	41	0.7%	41	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	41	0.7%	41	0.7%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	40	0.7%	2	0.0%	7	0.1%	0	0.0%	50	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	1.6%	93	1.6%
Total	44	0.8%	3	0.0%	24	0.4%	251	4.4%	322	5.7%
Achievable Participation										
Pricing with Technology	120	2.1%	32	0.6%	46	0.8%	19	0.3%	217	3.8%
Pricing without Technology	88	1.6%	2	0.0%	35	0.6%	35	0.6%	161	2.8%
Automated/Direct Load Control	10	0.2%	1	0.0%	3	0.0%	0	0.0%	14	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	38	0.7%	38	0.7%
Total	218	3.8%	34	0.6%	100	1.8%	249	4.4%	601	10.6%
Full Participation										
Pricing with Technology	280	4.9%	74	1.3%	135	2.4%	57	1.0%	546	9.6%
Pricing without Technology	49	0.9%	1	0.0%	23	0.4%	46	0.8%	119	2.1%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	329	5.8%	76	1.3%	173	3.0%	259	4.6%	837	14.7%



New York State Profile

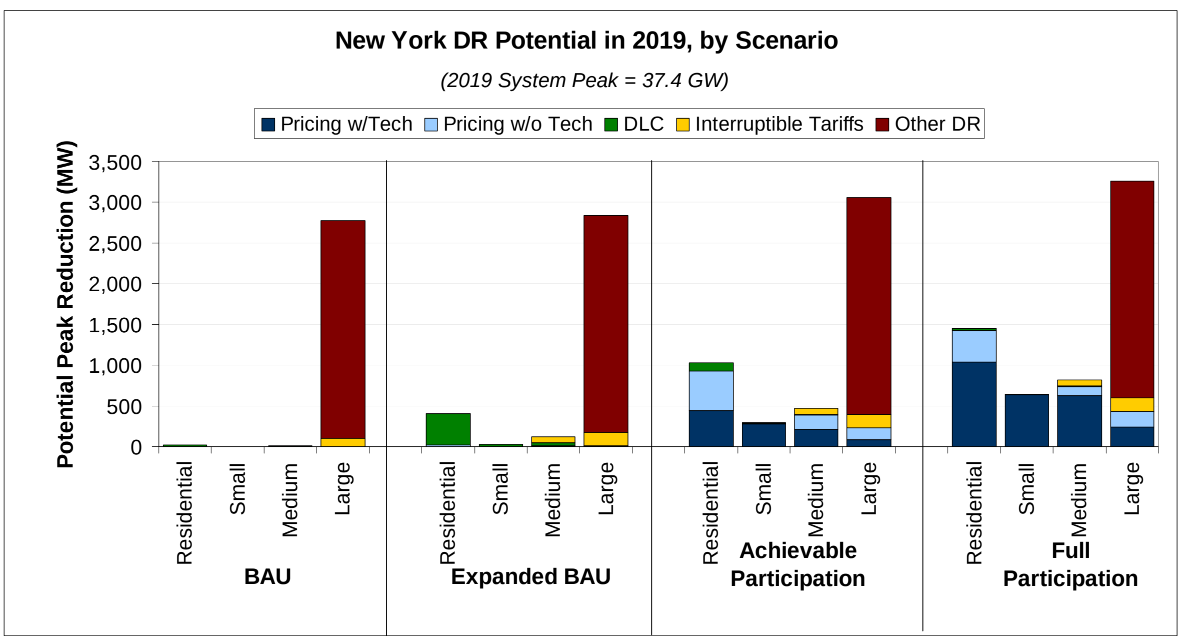
Key drivers of New York's demand response potential estimate include: a very high level of load participating in NYISO demand response Programs, a customer mix with almost 40% of the load from residential customers, and the potential to deploy AMI at a faster-than-average rate. New York has a lower than average residential CAC saturation at 16.7%. 'Pricing with technology' and DLC are cost effective for all customer classes in the state.

BAU: New York's existing demand response comes primarily from large C&I load participation in the NYISO market. This dominates the potential estimated across all scenarios.

Expanded BAU: Since current participation levels in NYISO demand response programs are substantially high, there is not much scope for growth in this program. Increase in impacts for this scenario is primarily derived from an expansion in residential DLC programs and Interruptible programs for large C&I customers.

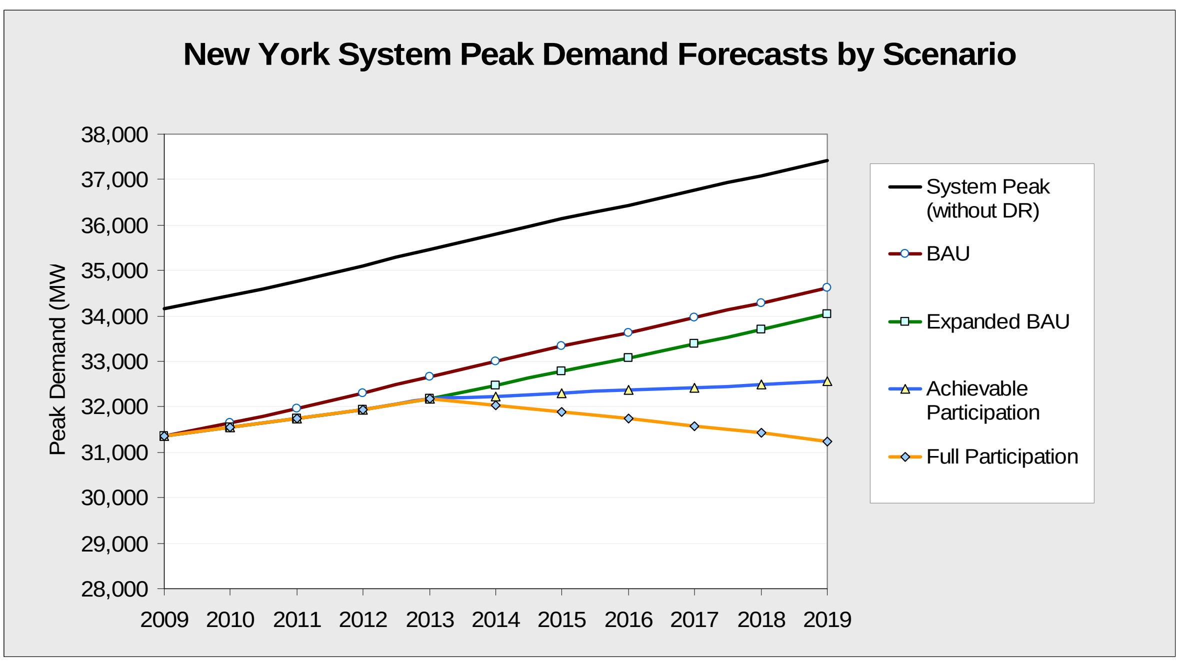
Achievable Participation: A moderately high share of residential load in the total drives a significant increase in demand response potential through pricing programs. For the C&I sector too, additional load reduction is derived through participation in pricing programs. However, impacts from 'Other DR' programs continue to dominate due to persistently high large C&I participation levels in NYISO market.

Full Participation: Higher participation of residential and C&I load (primarily small and medium C&I) in pricing programs drive potential increase in this scenario, as compared to the 'Achievable Participation' scenario. However, the impacts are dominated by high level of large C&I participation in NYISO programs.



Total Potential Peak Reduction from Demand Response in New York, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.3%	104	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	21	0.1%	0	0.0%	10	0.0%	2,772	7.4%	2,803	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	1	0.0%	11	0.0%	7	0.0%	39	0.1%
Automated/Direct Load Control	387	1.0%	25	0.1%	35	0.1%	0	0.0%	447	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	408	1.1%	25	0.1%	117	0.3%	2,839	7.6%	3,389	9.1%
Achievable Participation										
Pricing with Technology	443	1.2%	272	0.7%	215	0.6%	82	0.2%	1,011	2.7%
Pricing without Technology	485	1.3%	17	0.0%	168	0.4%	149	0.4%	818	2.2%
Automated/Direct Load Control	99	0.3%	6	0.0%	14	0.0%	0	0.0%	120	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,026	2.7%	295	0.8%	467	1.2%	3,063	8.2%	4,852	13.0%
Full Participation										
Pricing with Technology	1,035	2.8%	636	1.7%	627	1.7%	240	0.6%	2,538	6.8%
Pricing without Technology	392	1.0%	10	0.0%	111	0.3%	193	0.5%	706	1.9%
Automated/Direct Load Control	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,448	3.9%	647	1.7%	819	2.2%	3,265	8.7%	6,179	16.5%



North Carolina State Profile

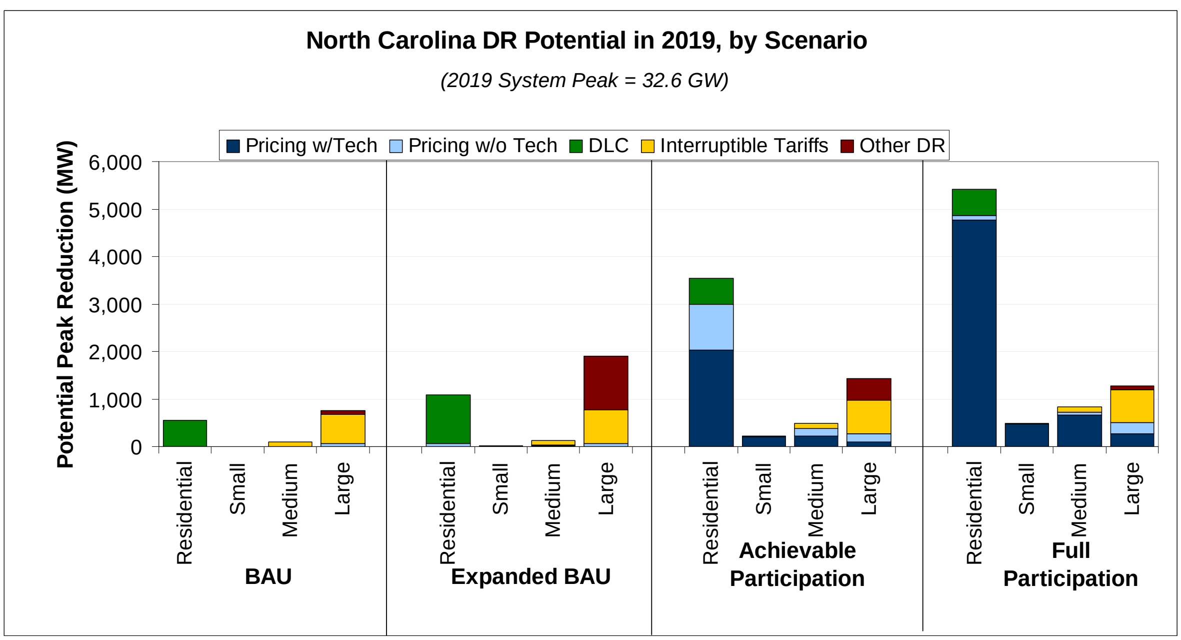
Key drivers of North Carolina's demand response potential estimate include: above average residential CAC saturation of 84%, an above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Carolina's existing demand response comes primarily from residential DLC and interruptible tariffs for the Medium and Large C&I classes. The state is also one of the few states with a significant portion of price induced demand response. Other DR for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the growth of Other DR programs for the Large C&I class and DLC for the residential class. Growth in dynamic pricing and existing interruptible tariffs account for the remaining portion.

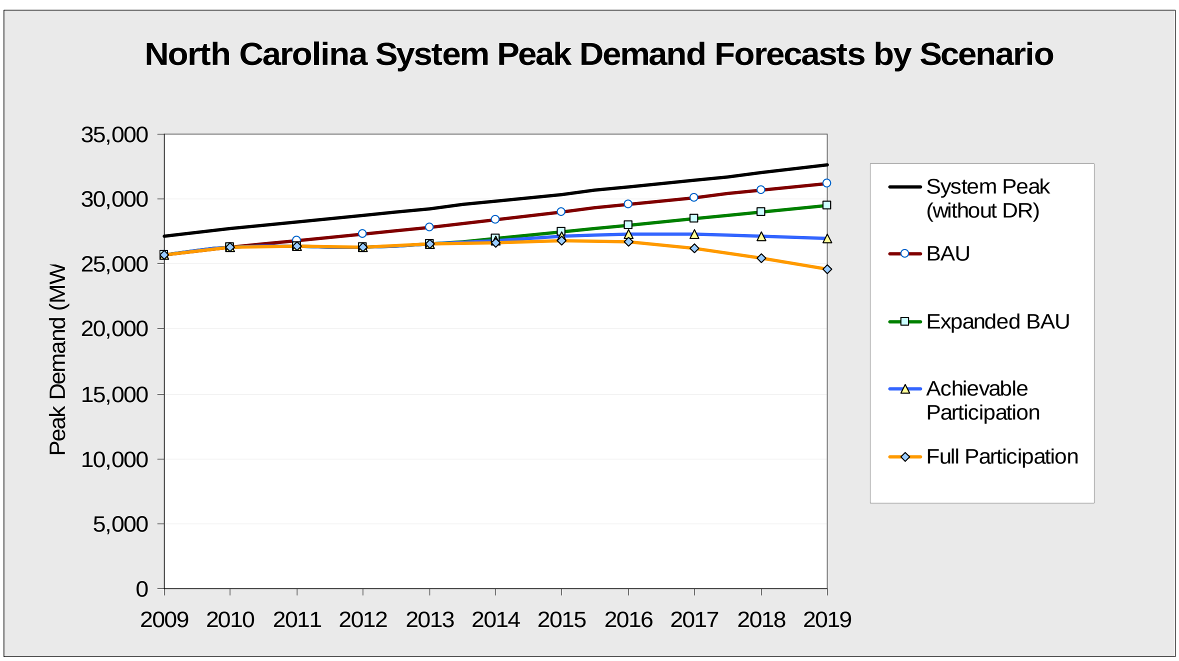
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents over 75% of the potential in this scenario. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in North Carolina, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	62	0.2%	62	0.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	93	0.3%	608	1.9%	701	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	547	1.7%	0	0.0%	93	0.3%	749	2.3%	1,388	4.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	67	0.2%	1	0.0%	11	0.0%	62	0.2%	140	0.4%
Automated/Direct Load Control	1,022	3.1%	14	0.0%	12	0.0%	0	0.0%	1,048	3.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,134	3.5%	1,134	3.5%
Total	1,089	3.3%	15	0.0%	132	0.4%	1,902	5.8%	3,137	9.6%
Achievable Participation										
Pricing with Technology	2,038	6.2%	203	0.6%	226	0.7%	94	0.3%	2,561	7.9%
Pricing without Technology	952	2.9%	11	0.0%	150	0.5%	171	0.5%	1,285	3.9%
Automated/Direct Load Control	547	1.7%	4	0.0%	5	0.0%	0	0.0%	555	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	464	1.4%	465	1.4%
Total	3,537	10.8%	218	0.7%	488	1.5%	1,436	4.4%	5,680	17.4%
Full Participation										
Pricing with Technology	4,768	14.6%	476	1.5%	659	2.0%	275	0.8%	6,178	18.9%
Pricing without Technology	98	0.3%	6	0.0%	73	0.2%	222	0.7%	399	1.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	5,413	16.6%	482	1.5%	840	2.6%	1,283	3.9%	8,017	24.6%



North Dakota State Profile

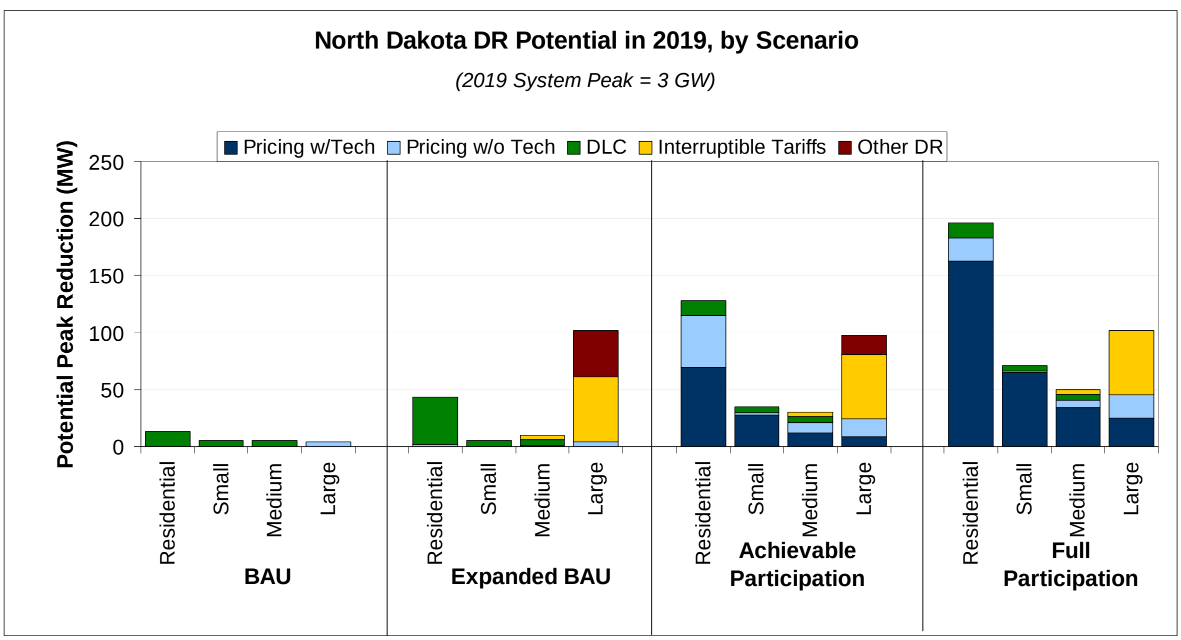
Key drivers of North Dakota's demand response potential estimate include: an above average share of peak demand (27%) in the Small C&I class and a moderate CAC saturation of 51%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Dakota's existing demand response comes primarily from DLC programs for all classes, except for the Large C&I class. Price induced demand response for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs and interruptible tariffs. Growth in the existing residential DLC programs accounts for the remaining portion.

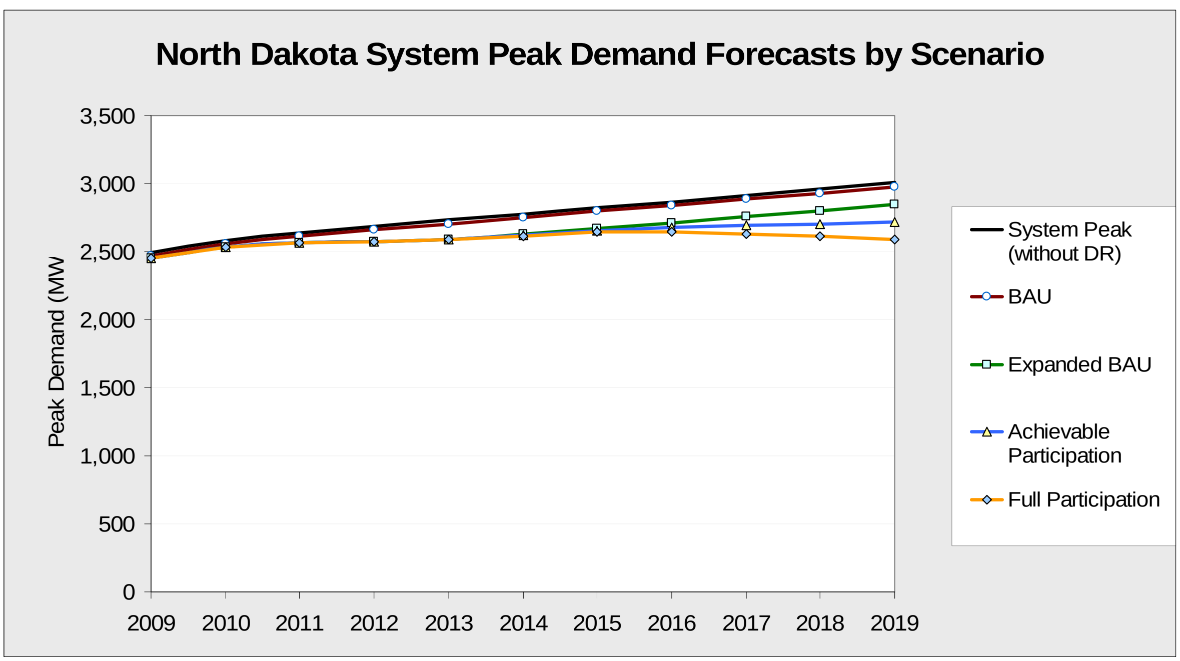
Achievable Participation: Dynamic pricing with enabling impacts accounts for approximately 40% of the increase in potential, with 10% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents almost 70% of the potential in this scenario. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, Other DR for the Large C&I class.



Total Potential Peak Reduction from Demand Response in North Dakota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	4	0.1%	4	0.1%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	13	0.4%	5	0.2%	5	0.2%	4	0.1%	28	0.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	4	0.1%	7	0.2%
Automated/Direct Load Control	42	1.4%	5	0.2%	5	0.2%	0	0.0%	52	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	41	1.4%	41	1.4%
Total	43	1.4%	5	0.2%	10	0.3%	102	3.4%	160	5.3%
Achievable Participation										
Pricing with Technology	70	2.3%	28	0.9%	12	0.4%	9	0.3%	118	3.9%
Pricing without Technology	45	1.5%	2	0.1%	9	0.3%	16	0.5%	72	2.4%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	17	0.6%	17	0.6%
Total	128	4.2%	35	1.2%	30	1.0%	97	3.2%	290	9.7%
Full Participation										
Pricing with Technology	163	5.4%	65	2.2%	34	1.1%	25	0.8%	287	9.6%
Pricing without Technology	20	0.7%	1	0.0%	6	0.2%	20	0.7%	48	1.6%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	196	6.5%	71	2.4%	50	1.7%	102	3.4%	419	13.9%



Ohio State Profile

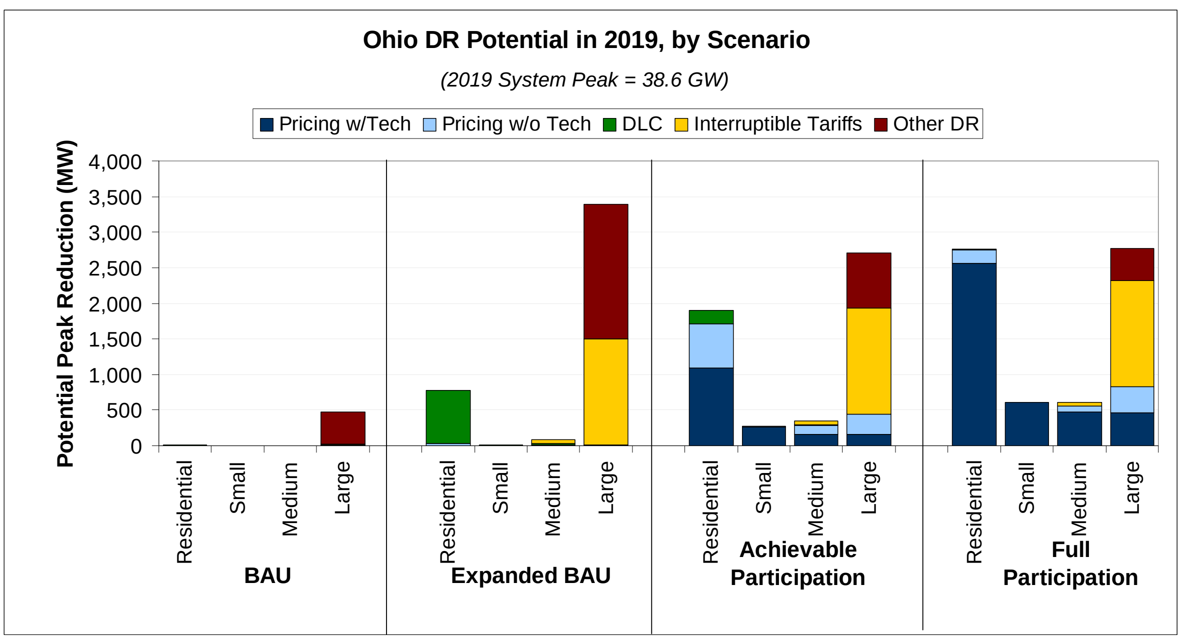
Key drivers of Ohio's demand response potential estimate include: a relatively high number of residential accounts at 5 million, higher-than-average residential CAC saturation of 63%, and a customer mix that has an above average share of peak demand in the large C&I class at 30%. AMI deployment is likely to take place at a lower-than-average rate for the state. 'Pricing with technology' is cost-effective for all customer classes. DLC is cost-effective for all customer classes.

BAU: Ohio's existing demand response comes primarily from large C&I load participation in 'Other DR' programs. Current demand response from DLC and 'Interruptible' programs is low.

Expanded BAU: Growth in demand response impacts is driven primarily through participation in 'Interruptible' and 'Other DR' programs for large C&I customers. Also, there is a significant growth in impacts coming from residential DLC programs. This is due to Ohio's high level of residential accounts with a higher than average CAC saturation.

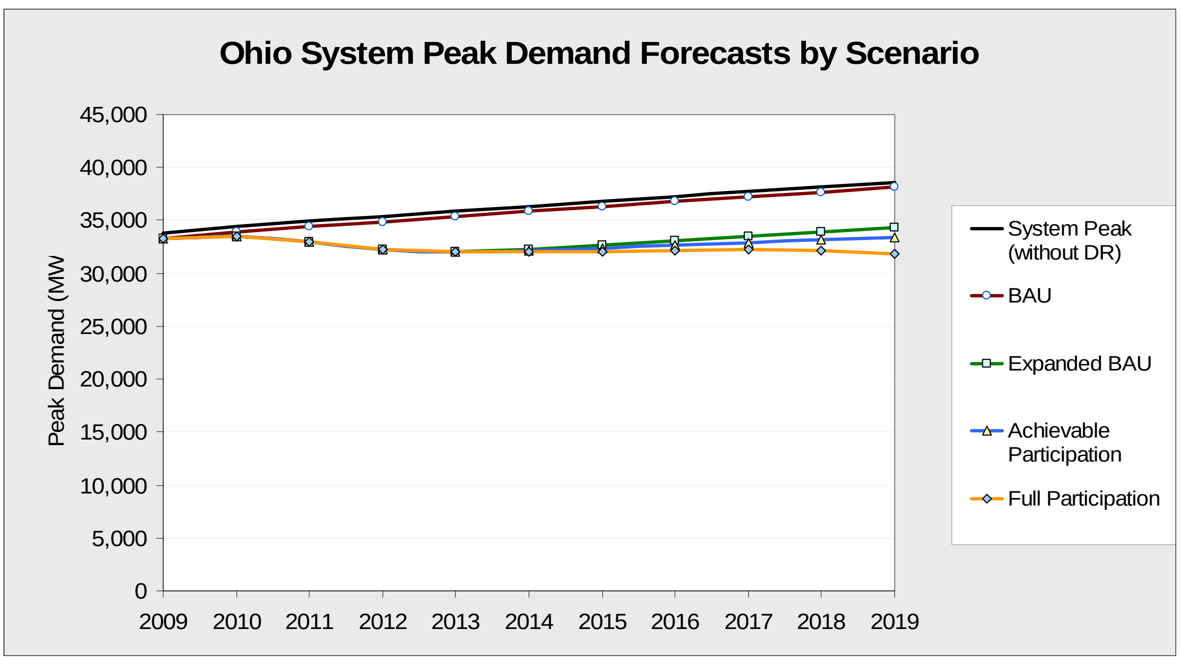
Achievable Participation: High residential customer participation in dynamic pricing options drives the increase in demand response potential for this scenario. C&I customers participate in 'pricing with technology' that also leads to an increase in impacts. Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to 'Other DR' program impacts.

Full Participation: Similar to the Achievable Participation scenario, increase in potential is driven by a high level of residential and C&I customer participation in 'pricing with technology' option.



Total Potential Peak Reduction from Demand Response in Ohio, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	13	0.0%	13	0.0%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	10	0.0%	0	0.0%	2	0.0%	471	1.2%	483	1.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	1	0.0%	7	0.0%	13	0.0%	54	0.1%
Automated/Direct Load Control	747	1.9%	11	0.0%	21	0.1%	0	0.0%	779	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,891	4.9%	1,891	4.9%
Total	779	2.0%	12	0.0%	83	0.2%	3,396	8.8%	4,270	11.1%
Achievable Participation										
Pricing with Technology	1,095	2.8%	258	0.7%	160	0.4%	156	0.4%	1,670	4.3%
Pricing without Technology	615	1.6%	16	0.0%	128	0.3%	284	0.7%	1,043	2.7%
Automated/Direct Load Control	190	0.5%	3	0.0%	9	0.0%	0	0.0%	202	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	772	2.0%	772	2.0%
Total	1,900	4.9%	277	0.7%	350	0.9%	2,704	7.0%	5,231	13.5%
Full Participation										
Pricing with Technology	2,562	6.6%	605	1.6%	468	1.2%	457	1.2%	4,091	10.6%
Pricing without Technology	190	0.5%	9	0.0%	87	0.2%	369	1.0%	655	1.7%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	2,761	7.1%	614	1.6%	610	1.6%	2,768	7.2%	6,753	17.5%



Oklahoma State Profile

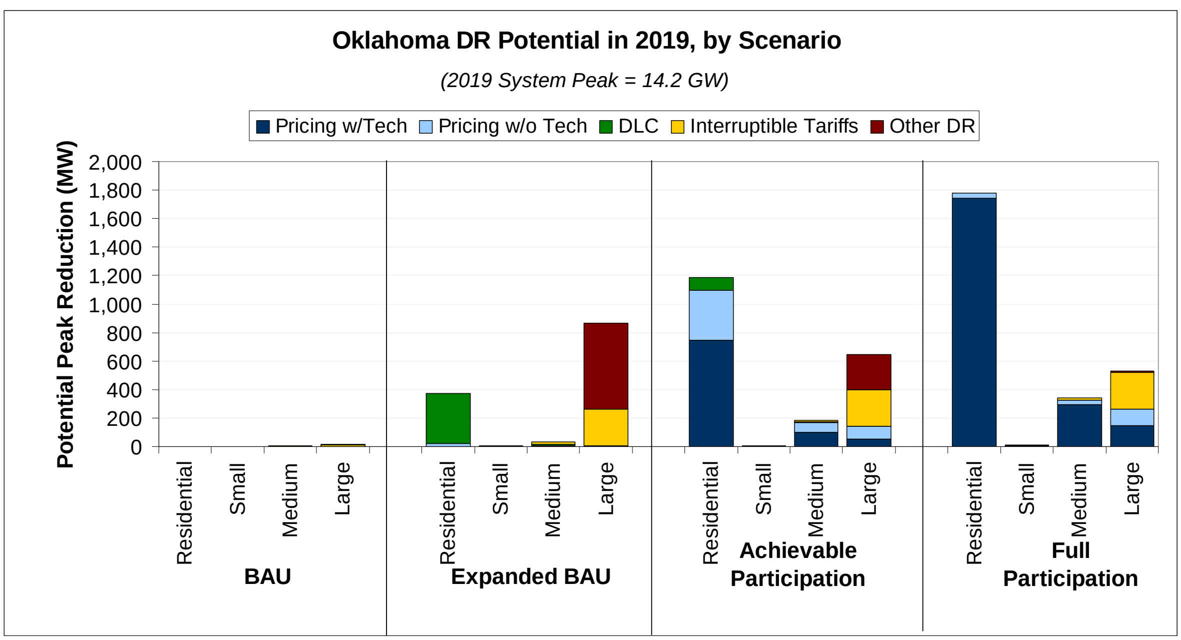
Key drivers of Oklahoma's demand response potential estimate include: higher-than-average residential CAC saturation of 84%, and a customer mix that has an above average share of peak demand in the residential class (50%). The level of existing demand response is low. 'Pricing with technology' is cost-effective for all customers, except for the small C&I class. DLC is cost effective for all customer classes in the state.

BAU: Oklahoma's existing demand response comes primarily from load enrolled in 'Interruptible' and 'Other DR' programs for C&I customers.

Expanded BAU: The residential sector has a high potential for growth due to high CAC saturation level, coupled with a low base of existing programs. In this scenario, growth in demand response impacts is driven primarily through the addition of residential DLC programs and through increase in large C&I load participation in 'Interruptible' and 'Other DR' programs.

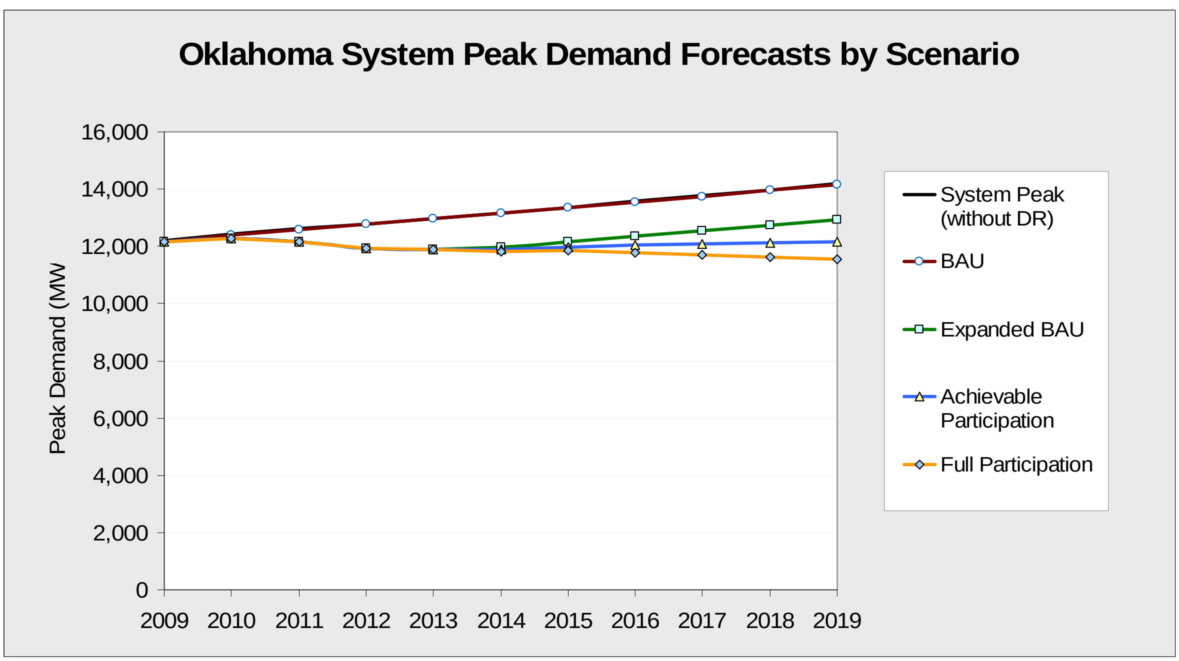
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through 'pricing with technology' option. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives increase in impacts. Increase in impacts is dominated by 'pricing with technology', which is cost-effective for all customer classes. Large C&I potential decreases, due to smaller per-customer impacts from pricing programs relative to Other DR.



Total Potential Peak Reduction from Demand Response in Oklahoma, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.0%	8	0.1%	11	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	0	0.0%	1	0.0%	3	0.0%	18	0.1%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	4	0.0%	4	0.0%	30	0.2%
Automated/Direct Load Control	351	2.5%	5	0.0%	13	0.1%	0	0.0%	369	2.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	605	4.3%	605	4.3%
Total	372	2.6%	6	0.0%	29	0.2%	867	6.1%	1,273	9.0%
Achievable Participation										
Pricing with Technology	746	5.3%	0	0.0%	101	0.7%	50	0.4%	896	6.3%
Pricing without Technology	350	2.5%	5	0.0%	67	0.5%	91	0.6%	514	3.6%
Automated/Direct Load Control	90	0.6%	1	0.0%	5	0.0%	0	0.0%	96	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	247	1.7%	247	1.7%
Total	1,185	8.3%	7	0.0%	185	1.3%	646	4.5%	2,023	14.2%
Full Participation										
Pricing with Technology	1,744	12.3%	0	0.0%	295	2.1%	146	1.0%	2,185	15.4%
Pricing without Technology	38	0.3%	7	0.1%	33	0.2%	118	0.8%	196	1.4%
Automated/Direct Load Control	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	1,782	12.6%	8	0.1%	339	2.4%	532	3.7%	2,662	18.7%



Oregon State Profile

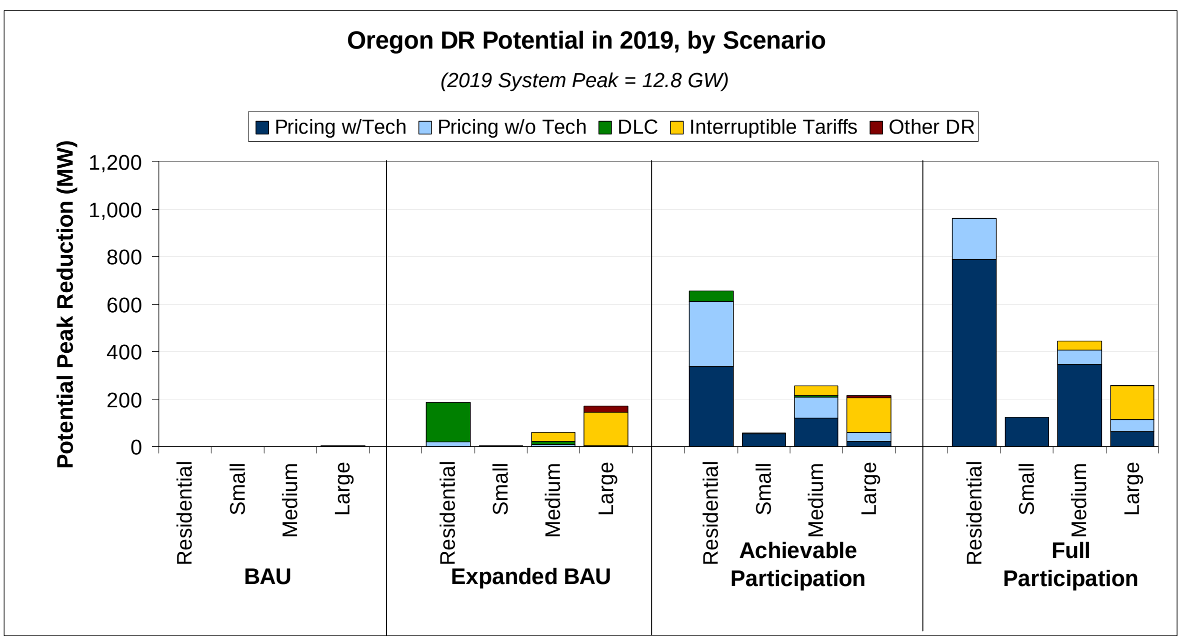
Key drivers of Oregon's demand response potential estimate include: a moderate residential base with 1.6 million accounts, a customer mix that has an above average share of peak demand in the medium C&I class (35%), and the potential to deploy AMI at a faster-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Oregon has a moderate residential CAC saturation value of 38%.

BAU: Oregon has a low level of existing demand response, primarily associated with large C&I participation in 'Other DR' programs for one of the IOUs in the region. Dominance on hydro power for generation in the Pacific Northwest region has historically led to low levels of demand response resources.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for residential customers, and through C&I load participation in 'Interruptible' and 'Other DR' programs. The potential for growth is significant, since existing demand response is at a very low level.

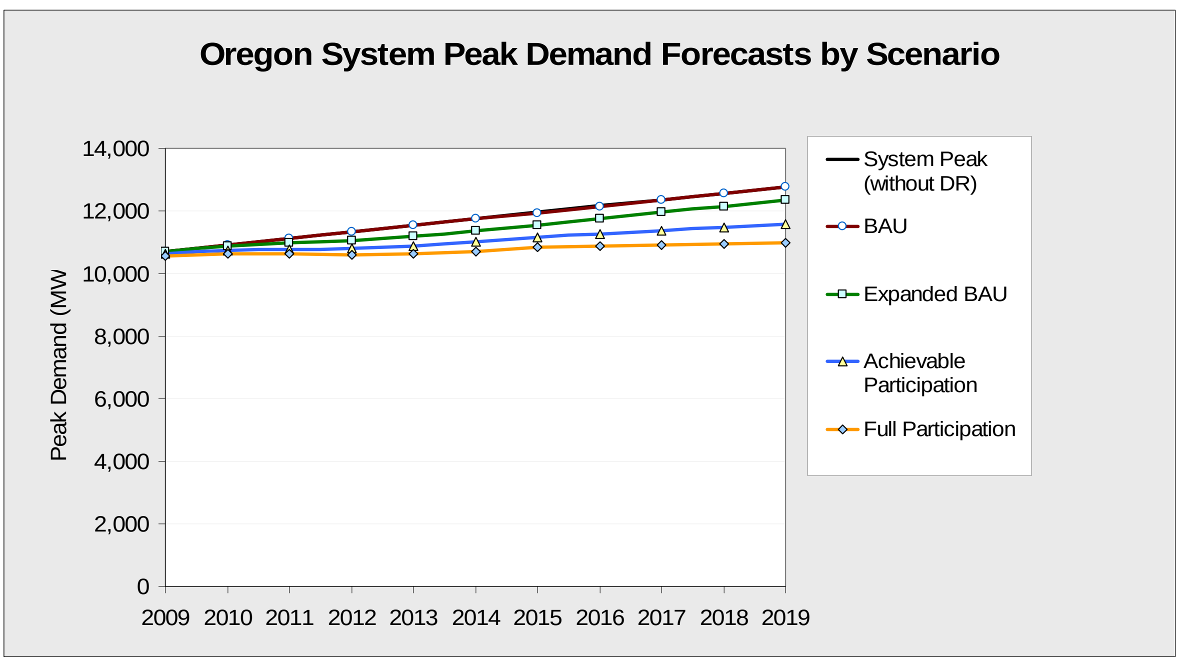
Achievable Participation: The increase in impacts is primarily associated with pricing programs. Participation of residential customers in 'Pricing with technology' option drives a significant increase in demand response potential. Also, impacts from 'pricing without technology' increase across all customer classes.

Full Participation: Similar to the Achievable Participation scenario, impacts are dominated by 'pricing with enabling technology'. Residential impacts grow substantially due to significantly higher participation in pricing programs. Among the three C&I rate classes, medium C&I impacts dominate due to its high share in the overall peak load.



Total Potential Peak Reduction from Demand Response in Oregon, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Total	2	0.0%	0	0.0%	0	0.0%	3	0.0%	5	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.1%	2	0.0%	29	0.2%
Automated/Direct Load Control	168	1.3%	4	0.0%	14	0.1%	0	0.0%	187	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	26	0.2%	26	0.2%
Total	187	1.5%	5	0.0%	61	0.5%	171	1.3%	424	3.3%
Achievable Participation										
Pricing with Technology	336	2.6%	52	0.4%	119	0.9%	21	0.2%	528	4.1%
Pricing without Technology	275	2.2%	3	0.0%	91	0.7%	39	0.3%	408	3.2%
Automated/Direct Load Control	43	0.3%	1	0.0%	6	0.0%	0	0.0%	50	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.1%	11	0.1%
Total	654	5.1%	57	0.4%	254	2.0%	214	1.7%	1,179	9.2%
Full Participation										
Pricing with Technology	786	6.2%	122	1.0%	347	2.7%	63	0.5%	1,318	10.3%
Pricing without Technology	173	1.4%	2	0.0%	58	0.5%	51	0.4%	284	2.2%
Automated/Direct Load Control	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Total	961	7.5%	124	1.0%	444	3.5%	259	2.0%	1,788	14.0%



Pennsylvania State Profile

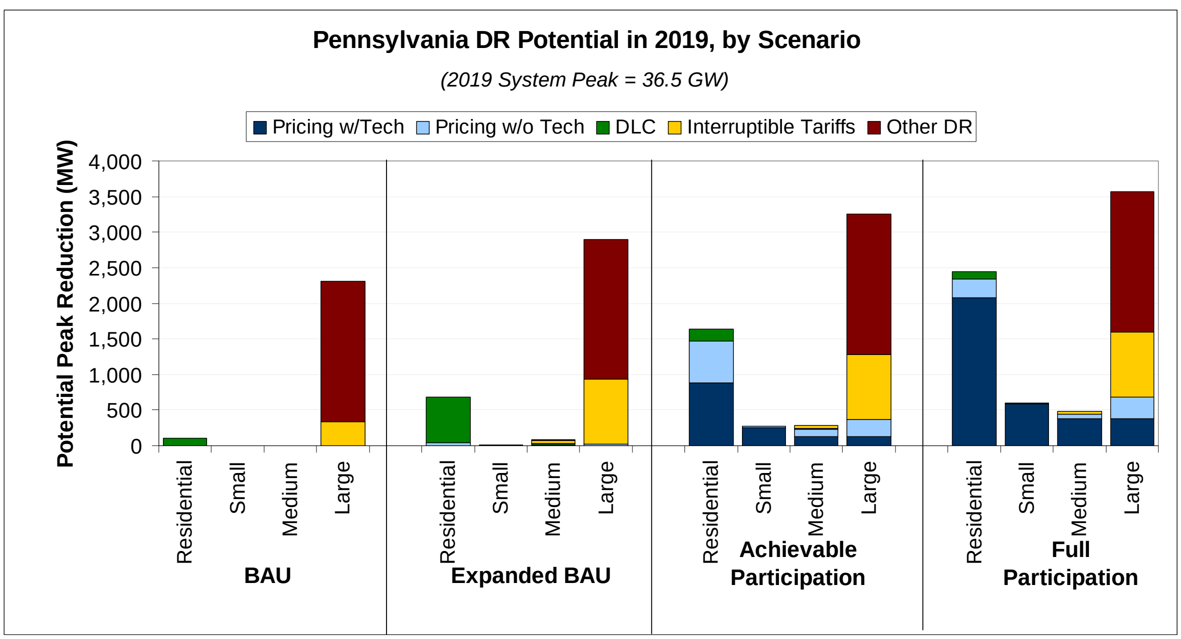
Key drivers of Pennsylvania's demand response potential estimate include: a relatively high level of load participation in the PJM market, a high residential population base with 50% CAC saturation, customer mix that has an above average share of peak demand for large C&I customers, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technology and DLC are cost-effective for all customer classes.

BAU: Pennsylvania's existing demand response comes primarily from large C&I load participation in the PJM market. A portion of the existing demand response potential also comes from legacy interruptible programs in the state, along with residential DLC program.

Expanded BAU: Growth in demand response impacts is driven primarily through the increase of 'Other DR' programs for the large C&I class (due to higher load participation in the PJM market), and the expansion of DLC programs for residential customers. Load reduction potential associated with interruptible programs also grows, due to Pennsylvania's high share of large C&I load.

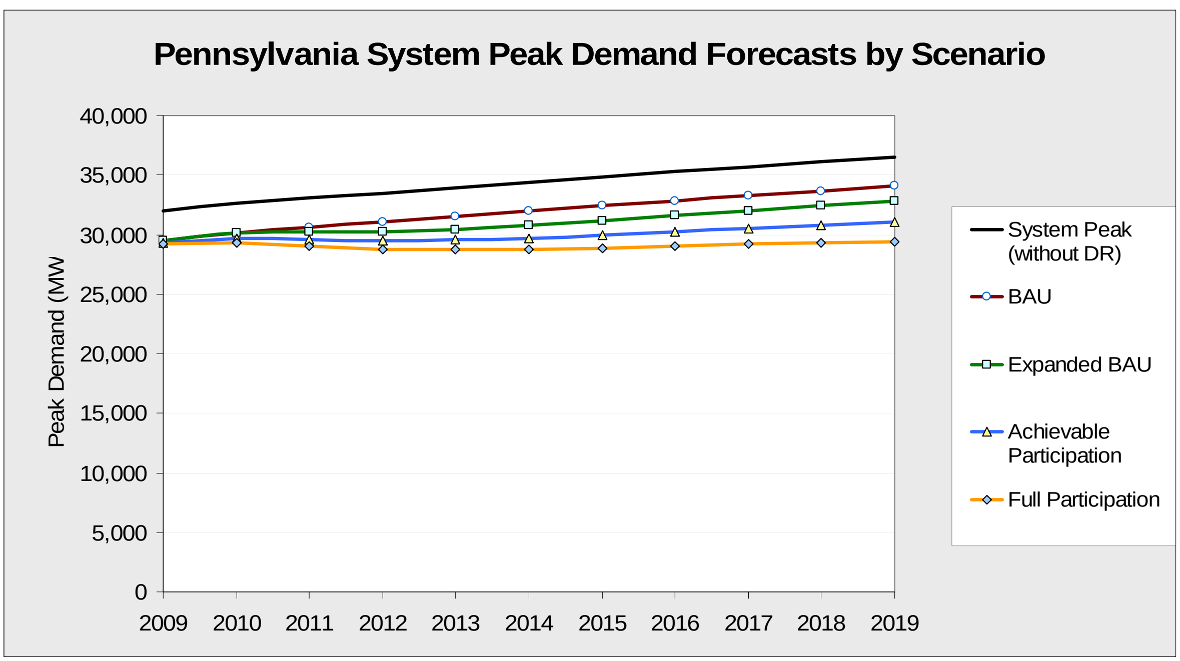
Achievable Participation: For this scenario, growth in residential impacts is associated with the pricing options. C&I customer participation in 'pricing with technology' cause a growth in potential. 'Other DR' programs continue to dominate the load reduction potential for large C&I customers.

Full Participation: Similar to the Achievable Participation scenario, high residential and C&I customer participation in the pricing options (primarily 'pricing with technology') drives the increase in impacts. 'Other DR' programs for large C&I customers maintain their large share in the total potential.



Total Potential Peak Reduction from Demand Response in Pennsylvania, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	338	0.9%	338	0.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	108	0.3%	0	0.0%	0	0.0%	2,307	6.3%	2,415	6.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	46	0.1%	1	0.0%	10	0.0%	16	0.0%	73	0.2%
Automated/Direct Load Control	641	1.8%	12	0.0%	27	0.1%	0	0.0%	679	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	687	1.9%	13	0.0%	79	0.2%	2,901	7.9%	3,680	10.1%
Achievable Participation										
Pricing with Technology	887	2.4%	253	0.7%	129	0.4%	129	0.4%	1,398	3.8%
Pricing without Technology	582	1.6%	16	0.0%	101	0.3%	235	0.6%	934	2.6%
Automated/Direct Load Control	166	0.5%	3	0.0%	11	0.0%	0	0.0%	180	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	1,635	4.5%	272	0.7%	283	0.8%	3,250	8.9%	5,439	14.9%
Full Participation										
Pricing with Technology	2,075	5.7%	592	1.6%	377	1.0%	378	1.0%	3,422	9.4%
Pricing without Technology	266	0.7%	10	0.0%	66	0.2%	305	0.8%	647	1.8%
Automated/Direct Load Control	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	2,450	6.7%	602	1.6%	486	1.3%	3,568	9.8%	7,105	19.5%



Rhode Island State Profile

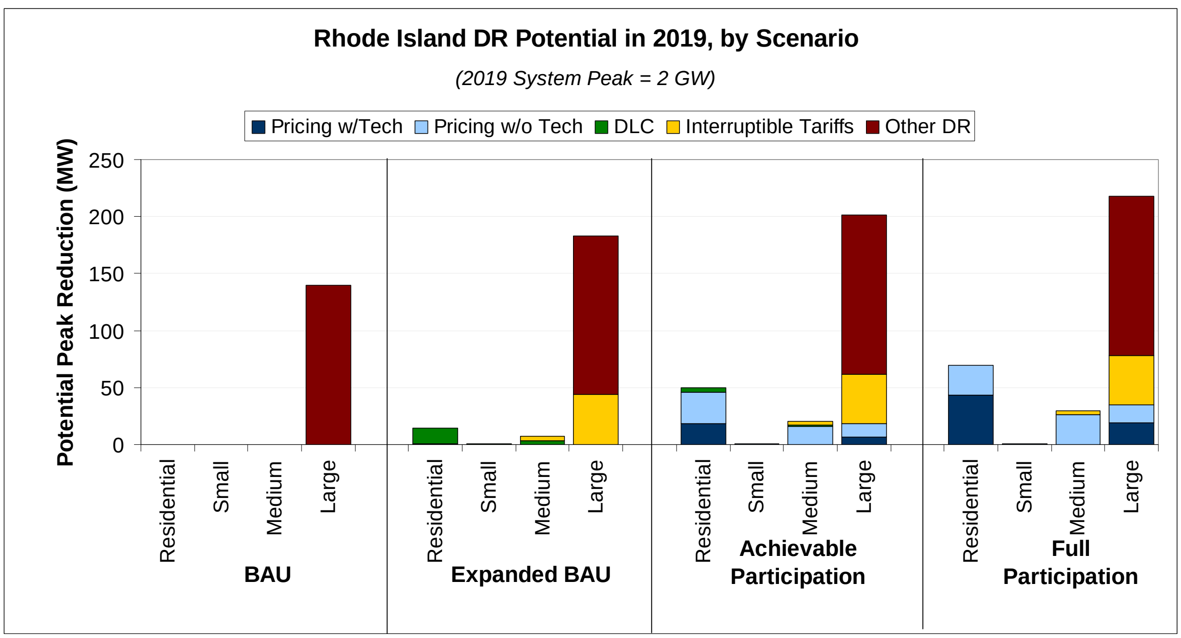
Rhode Island has a higher than average share of large C&I peak load (29%). The state's demand response potential is driven by large C&I load participation in the ISO-NE market. Rhode Island has a lower than average residential CAC saturation at 12%. Dynamic pricing with enabling technology is cost-effective only for residential and large C&I customers, thereby restricting the potential that can be derived from this option. DLC is cost-effective for all customer classes. It has a lower than average AMI deployment rate.

BAU: Rhode Island's existing demand response is derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Also, there is a potential for growth in residential DLC programs.

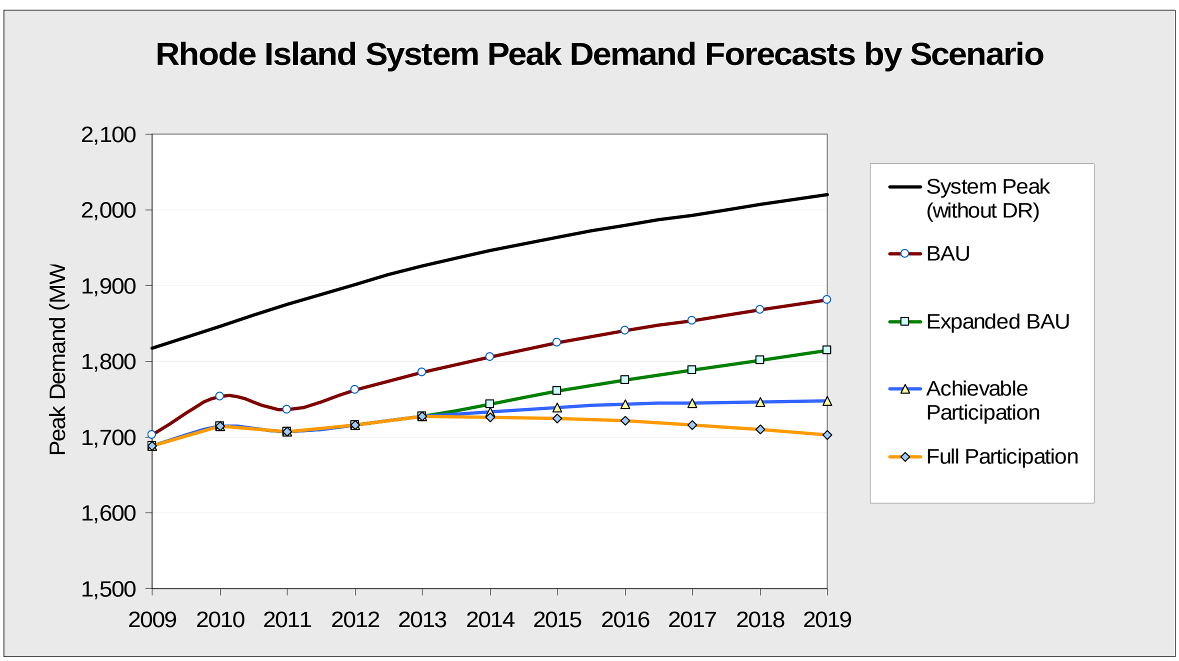
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived from pricing options, primarily from residential customers and to a smaller extent from medium C&I customers. Since 'pricing with technology' is cost-effective only for residential and large C&I customers, there is a low growth in potential associated with this option. Potential through large C&I load participation in the ISO-NE market dominates overall other types of demand response programs.

Full Participation: Similar to the Achievable Participation scenario, increase in customer participation in pricing options, primarily for residential and medium C&I customers, drives the increase in impacts. Similar to the other scenarios, large C&I load maintains high participation levels in the ISO-NE market.



Total Potential Peak Reduction from Demand Response in Rhode Island, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.1%
Automated/Direct Load Control	14	0.7%	1	0.0%	3	0.2%	0	0.0%	18	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	15	0.7%	1	0.0%	7	0.4%	183	9.1%	206	10.2%
Achievable Participation										
Pricing with Technology	19	0.9%	0	0.0%	0	0.0%	7	0.3%	25	1.2%
Pricing without Technology	28	1.4%	1	0.0%	16	0.8%	12	0.6%	56	2.8%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.1%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	50	2.5%	1	0.0%	20	1.0%	201	10.0%	273	13.5%
Full Participation										
Pricing with Technology	44	2.2%	0	0.0%	0	0.0%	19	0.9%	63	3.1%
Pricing without Technology	26	1.3%	1	0.0%	26	1.3%	15	0.8%	68	3.4%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	70	3.4%	1	0.0%	30	1.5%	218	10.8%	318	15.7%



South Carolina State Profile

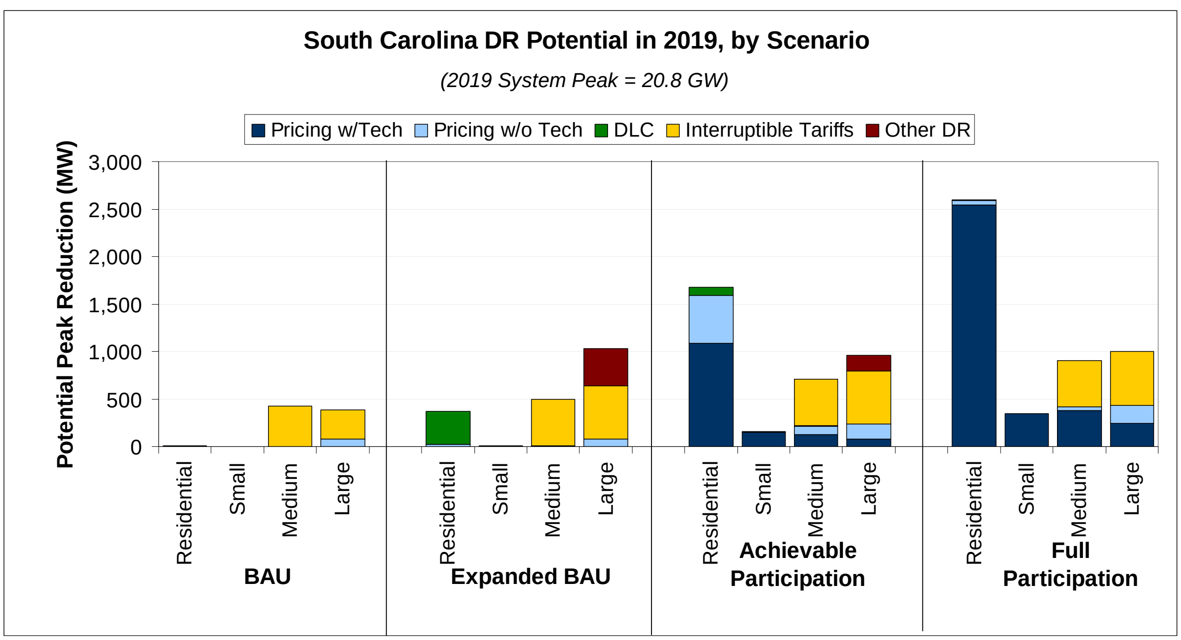
Key drivers of South Carolina's demand response potential estimate include: higher-than-average residential CAC saturation of 84 percent and a moderate amount of existing demand response. An expectation for AMI deployment that slightly lags the national average could lead to less potential demand response. Enabling technologies and DLC are cost-effective for all customer classes in the state.

BAU: South Carolina's existing demand response comes primarily from an interruptible tariff program for both Medium and Large C&I classes. A small amount comes from pricing without technology for the Large C&I class.

Expanded BAU: Growth in demand response impacts are driven through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. Significant growth also results from residential participation in DLC programs and large C&I customer participation in Interruptible tariffs.

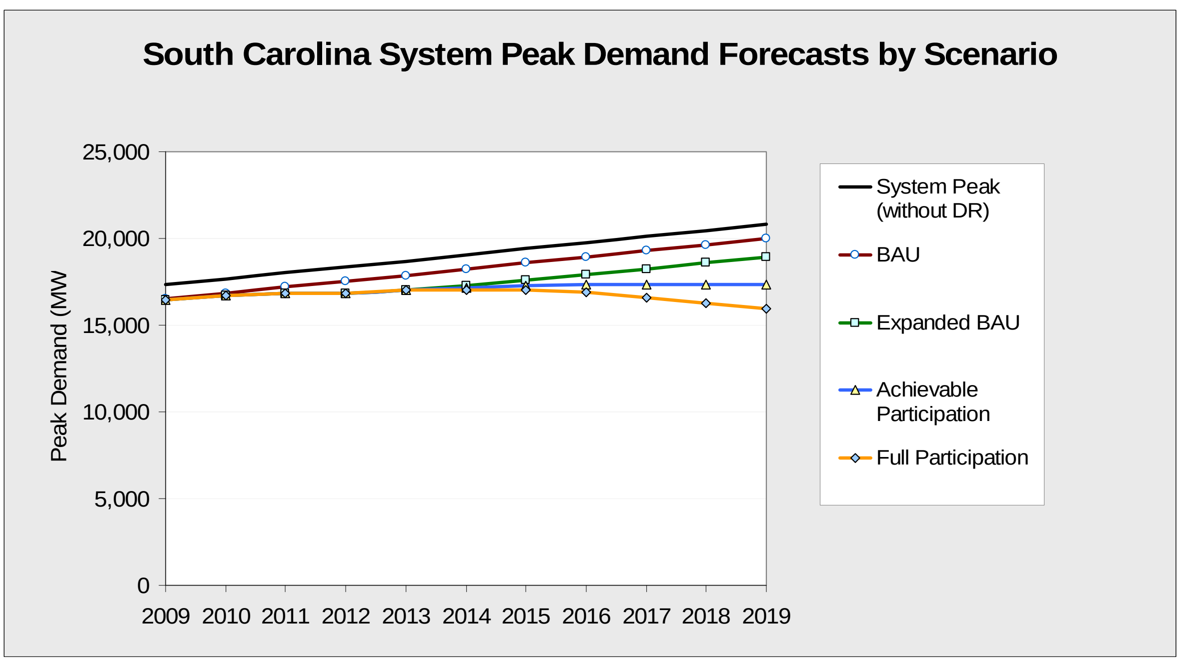
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing, with the majority of customers increasing impacts through the use of enabling technologies. Medium C&I demand response potential is slightly increased through the addition of dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Residential potential demand response increases dramatically due to dynamic pricing with technology reaching more customers. Again, high CAC saturation leads to large demand response potential for the residential sector. Dynamic pricing with technology modestly increases the demand response potential for the remaining sectors.



Total Potential Peak Reduction from Demand Response in South Carolina, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	76	0.4%	76	0.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	423	2.0%	307	1.5%	730	3.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	5	0.0%	0	0.0%	423	2.0%	383	1.8%	811	3.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	27	0.1%	0	0.0%	5	0.0%	76	0.4%	109	0.5%
Automated/Direct Load Control	343	1.6%	5	0.0%	5	0.0%	0	0.0%	353	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	394	1.9%	395	1.9%
Total	370	1.8%	6	0.0%	499	2.4%	1,034	5.0%	1,909	9.2%
Achievable Participation										
Pricing with Technology	1,086	5.2%	147	0.7%	129	0.6%	83	0.4%	1,445	6.9%
Pricing without Technology	506	2.4%	8	0.0%	86	0.4%	150	0.7%	750	3.6%
Automated/Direct Load Control	87	0.4%	1	0.0%	2	0.0%	0	0.0%	91	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	161	0.8%	161	0.8%
Total	1,679	8.1%	156	0.8%	706	3.4%	957	4.6%	3,498	16.8%
Full Participation										
Pricing with Technology	2,541	12.2%	344	1.7%	377	1.8%	242	1.2%	3,503	16.8%
Pricing without Technology	50	0.2%	4	0.0%	42	0.2%	195	0.9%	291	1.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,596	12.5%	348	1.7%	907	4.4%	1,000	4.8%	4,851	23.3%



South Dakota State Profile

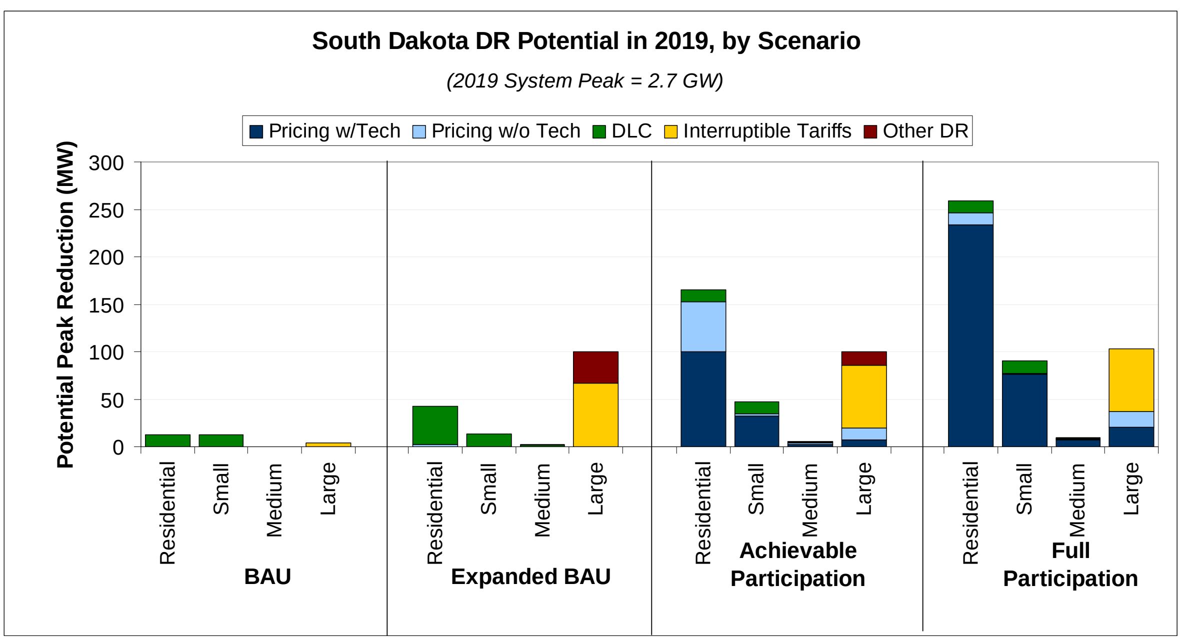
Key drivers of South Dakota's demand response potential estimate include: higher-than-average residential CAC saturation of 71 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes and Residential customers. Also, AMI deployment that potentially lags the national average could lead to slower realized demand response potential.

BAU: South Dakota's existing demand response comes primarily from direct load control for both the Residential and Small C&I classes. A small amount of demand response comes from the Large C&I class, in the form of interruptible tariffs.

Expanded BAU: Growth in demand response is driven equally through an interruptible tariff program and other demand response programs for the Large C&I class. The other category of demand response programs does not currently exist in the state. Residential DLC contributes to increased demand response potential, as well.

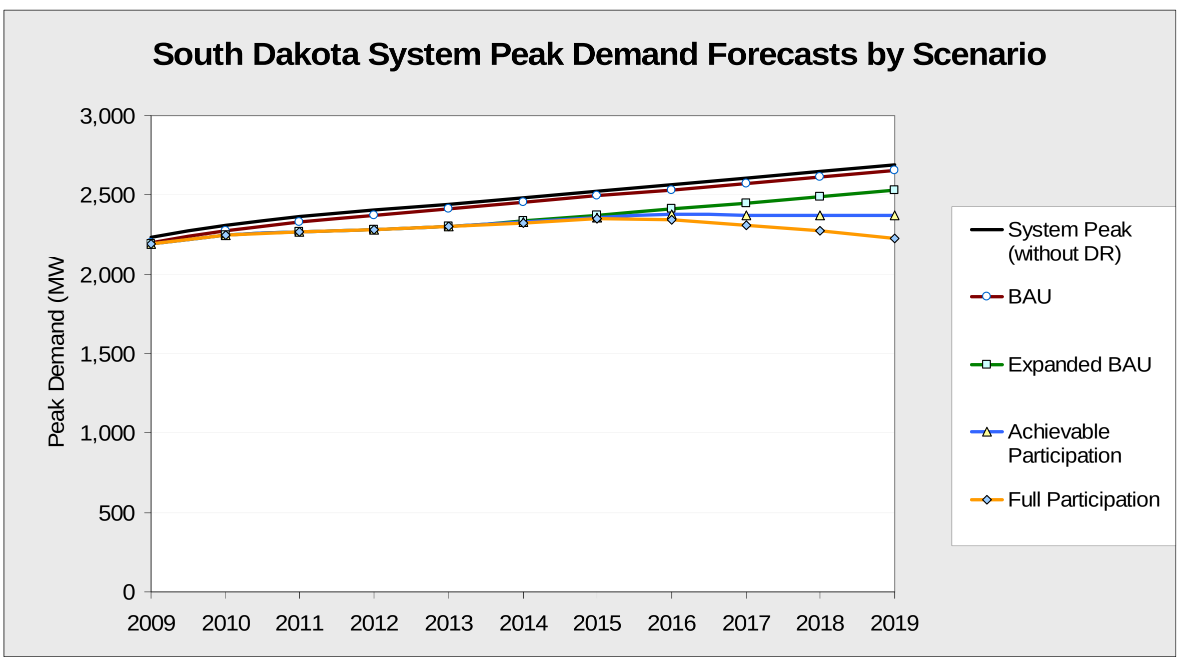
Achievable Participation: Increases in this scenario result from dynamic pricing programs, both with and without enabling technology, primarily through participation of residential and small C&I customers in these pricing programs.

Full Participation: Demand response potential is further realized through increases in both dynamic pricing programs. Large C&I customers that were in other demand response programs have shifted in to both dynamic pricing programs, with the majority enrolling in the with technology option. Again, higher-than-average CAC saturation results in the Residential class having the largest amount of potential demand response, with a very large fraction coming in the form of dynamic pricing with enabling technologies.



Total Potential Peak Reduction from Demand Response in South Dakota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	4	0.2%	4	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	13	0.5%	13	0.5%	0	0.0%	4	0.2%	30	1.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	0	0.0%	3	0.1%
Automated/Direct Load Control	41	1.5%	13	0.5%	1	0.0%	0	0.0%	55	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	33	1.2%	33	1.2%
Total	43	1.6%	13	0.5%	2	0.1%	100	3.7%	158	5.9%
Achievable Participation										
Pricing with Technology	100	3.7%	33	1.2%	2	0.1%	7	0.3%	142	5.3%
Pricing without Technology	53	2.0%	2	0.1%	2	0.1%	13	0.5%	69	2.6%
Automated/Direct Load Control	13	0.5%	13	0.5%	1	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	14	0.5%	14	0.5%
Total	165	6.2%	48	1.8%	6	0.2%	100	3.7%	318	11.8%
Full Participation										
Pricing with Technology	234	8.7%	76	2.8%	7	0.3%	20	0.8%	337	12.6%
Pricing without Technology	13	0.5%	1	0.0%	1	0.0%	16	0.6%	31	1.2%
Automated/Direct Load Control	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	259	9.6%	90	3.4%	9	0.3%	103	3.8%	462	17.2%



Tennessee State Profile

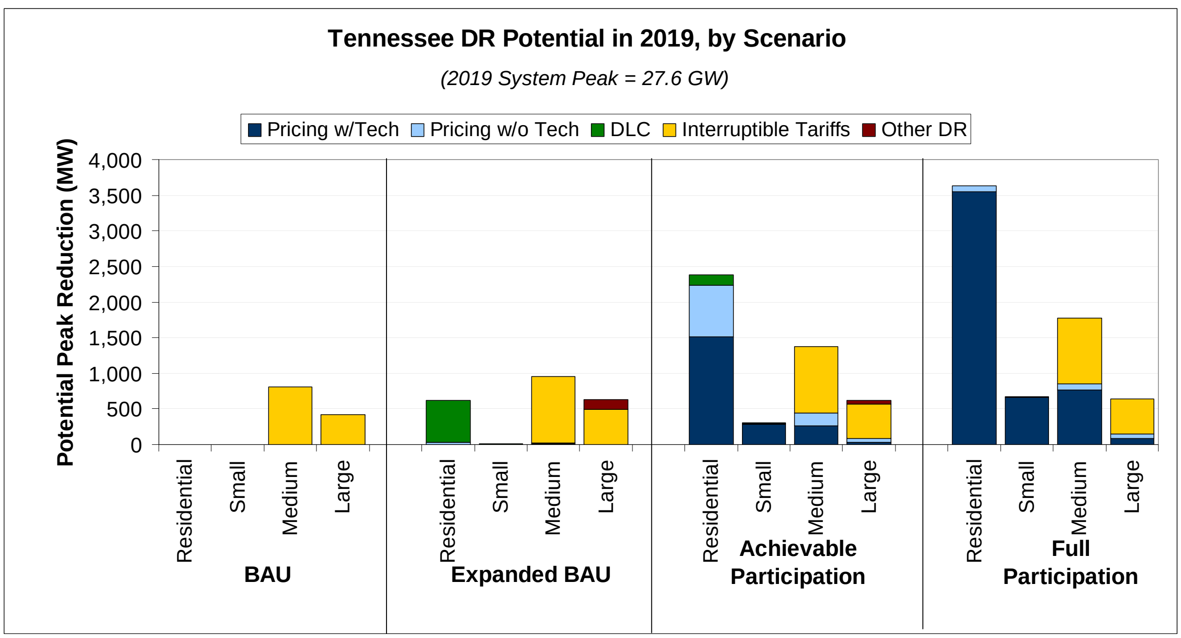
Key drivers of Tennessee's demand response potential estimate include: higher-than-average residential CAC saturation of 81 percent and a moderate amount of existing demand response. Dynamic pricing with enabling technologies are cost-effective for all customer classes. AMI deployment that potentially lags the national average could lead to slower realized demand response potential. Large C&I represents a significantly smaller-than-average share of peak (6%), resulting in a smaller state-wide impact for this class.

BAU: Tennessee has existing demand response for Medium and Large C&I classes, through participation in Interruptible tariffs. A smaller impact comes from Large C&I due to this class representing a smaller portion of overall peak.

Expanded BAU: Demand response potential increase is driven by DLC for Residential customers. Smaller increases result Interruptible and 'Other DR' programs, for the remaining classes.

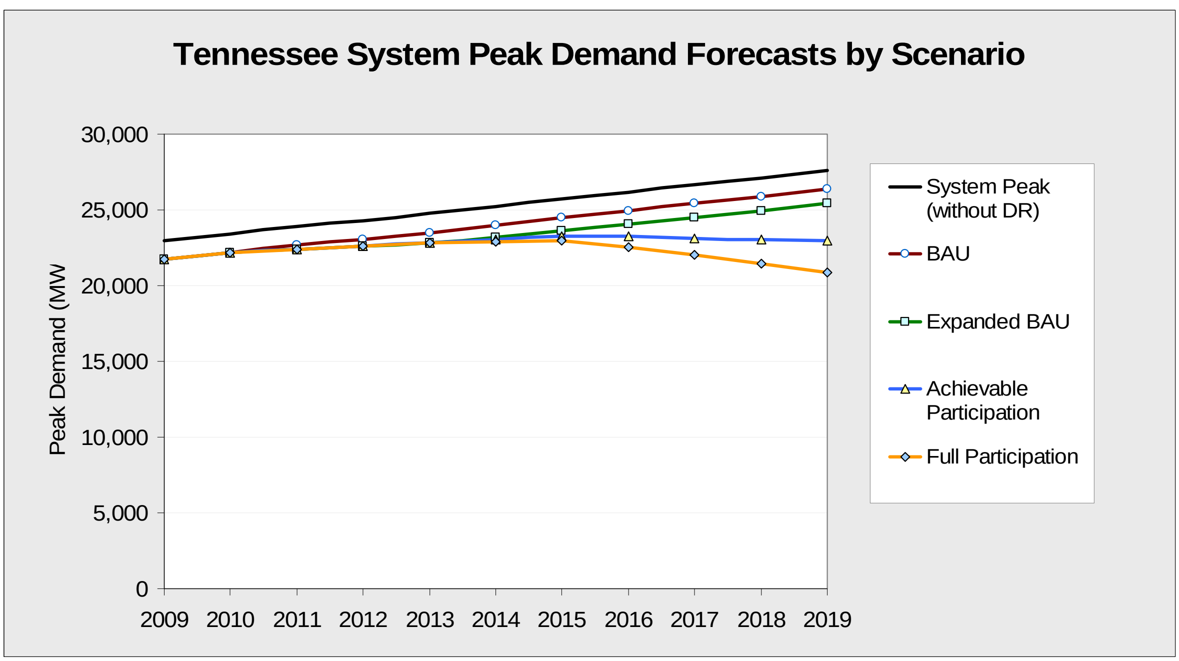
Achievable Participation: Significant potential comes from the two pricing programs, mostly for the residential class of customers. Residential potential demand response is driven by high CAC saturation, leading to this class representing a large share of system peak.

Full Participation: Demand response potential increases are driven mostly by pricing with enabling technology, for all customer classes. This is most pronounced for the residential customers who switch from DLC programs in to pricing with technologies. Again, high CAC saturation drives most of the potential impact for this class of customers.



Total Potential Peak Reduction from Demand Response in Tennessee, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	809	2.9%	425	1.5%	1,234	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	809	2.9%	425	1.5%	1,234	4.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	1	0.0%	8	0.0%	2	0.0%	41	0.1%
Automated/Direct Load Control	586	2.1%	9	0.0%	13	0.0%	0	0.0%	608	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.5%	137	0.5%
Total	617	2.2%	10	0.0%	951	3.4%	627	2.3%	2,204	8.0%
Achievable Participation										
Pricing with Technology	1,515	5.5%	282	1.0%	262	0.9%	29	0.1%	2,087	7.6%
Pricing without Technology	717	2.6%	16	0.1%	174	0.6%	52	0.2%	959	3.5%
Automated/Direct Load Control	149	0.5%	2	0.0%	5	0.0%	0	0.0%	156	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	55	0.2%	56	0.2%
Total	2,381	8.6%	300	1.1%	1,370	5.0%	624	2.3%	4,676	16.9%
Full Participation										
Pricing with Technology	3,544	12.8%	660	2.4%	765	2.8%	83	0.3%	5,053	18.3%
Pricing without Technology	85	0.3%	8	0.0%	84	0.3%	67	0.2%	245	0.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	3,629	13.1%	668	2.4%	1,779	6.4%	639	2.3%	6,715	24.3%



Texas State Profile

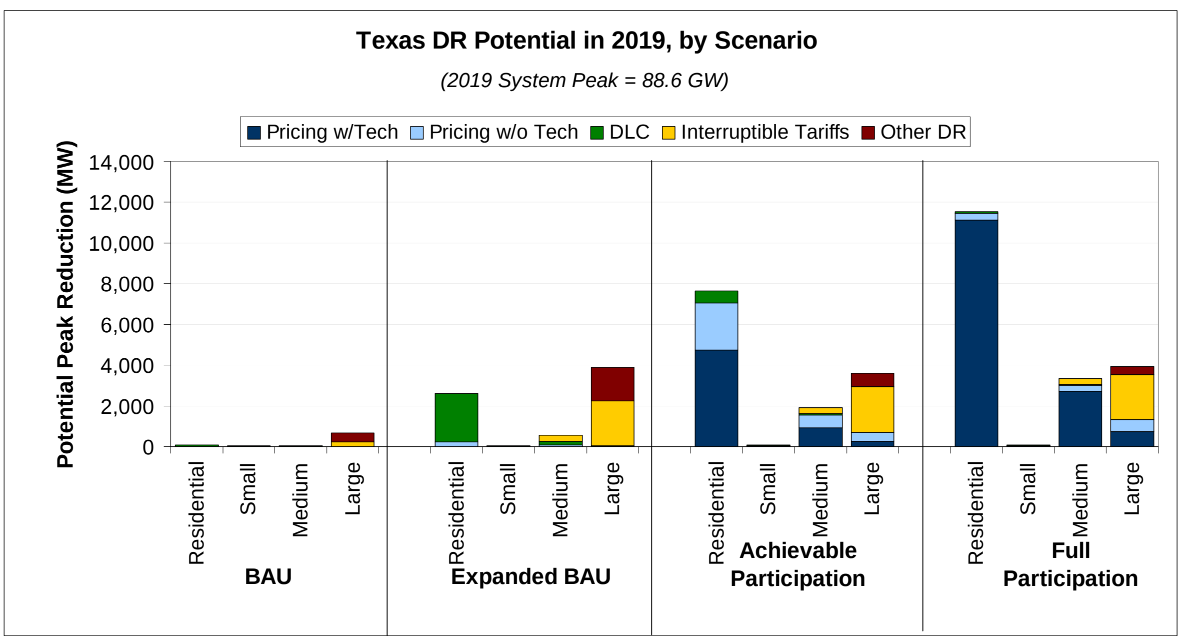
Key drivers of demand response potential in Texas include: higher-than-average residential CAC saturation of 80 percent and very little existing demand response. Enabling technologies are cost-effective for all customer classes, except for small C&I customers. Also, potential AMI deployment significantly leads the national average and could lead to faster realization of potential demand response.

BAU: The majority of Texas's current demand response comes from the Large C&I class, through participation in Interruptible tariffs and 'Other DR' programs in the ERCOT market. The state has a small amount of direct load control for the other customer classes.

Expanded BAU: High CAC saturation leads to growth in residential demand response potential through direct load control. Most of the remaining growth in potential comes from the Large C&I class, through participation in Interruptible and 'Other DR' programs.

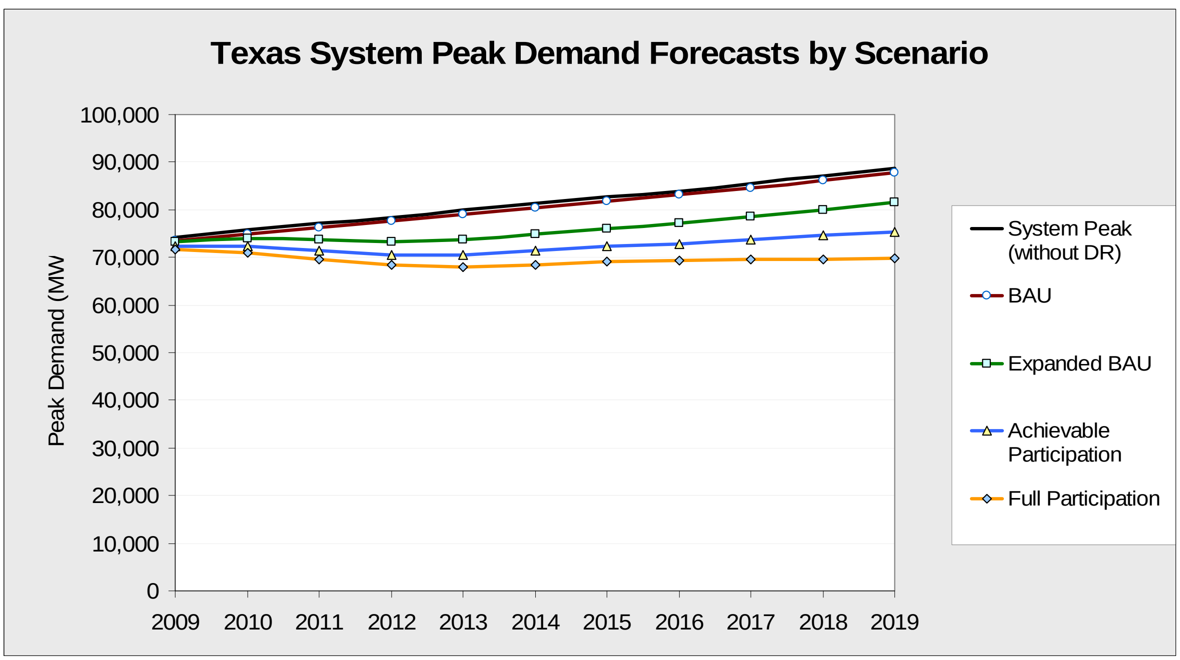
Achievable Participation: High CAC saturation coupled with faster-than-average AMI deployment lead to significant potential acceptance of dynamic pricing for the Residential class. Some residential growth results from customers shifting from DLC programs in to the two dynamic pricing programs. Small increases in demand response potential result from medium and large C&I customers enrolling in both dynamic pricing programs.

Full Participation: Significant demand response potential comes from the Residential class, driven primarily by high CAC saturation and a faster-than-average AMI penetration rate. Both Medium and Large C&I classes show growth in demand response through increased enrollment in dynamic pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Texas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	232	0.3%	232	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	79	0.1%	39	0.0%	48	0.1%	645	0.7%	810	0.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	236	0.3%	1	0.0%	70	0.1%	35	0.0%	343	0.4%
Automated/Direct Load Control	2,371	2.7%	39	0.0%	190	0.2%	0	0.0%	2,599	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	3	0.0%	1,640	1.9%	1,643	1.9%
Total	2,607	2.9%	40	0.0%	543	0.6%	3,894	4.4%	7,083	8.0%
Achievable Participation										
Pricing with Technology	4,758	5.4%	0	0.0%	925	1.0%	250	0.3%	5,932	6.7%
Pricing without Technology	2,289	2.6%	27	0.0%	615	0.7%	454	0.5%	3,386	3.8%
Automated/Direct Load Control	614	0.7%	39	0.0%	79	0.1%	0	0.0%	732	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	680	0.8%	681	0.8%
Total	7,661	8.6%	66	0.1%	1,900	2.1%	3,602	4.1%	13,230	14.9%
Full Participation										
Pricing with Technology	11,129	12.6%	0	0.0%	2,703	3.1%	730	0.8%	14,562	16.4%
Pricing without Technology	318	0.4%	37	0.0%	298	0.3%	588	0.7%	1,241	1.4%
Automated/Direct Load Control	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	11,525	13.0%	75	0.1%	3,330	3.8%	3,949	4.5%	18,880	21.3%



Utah State Profile

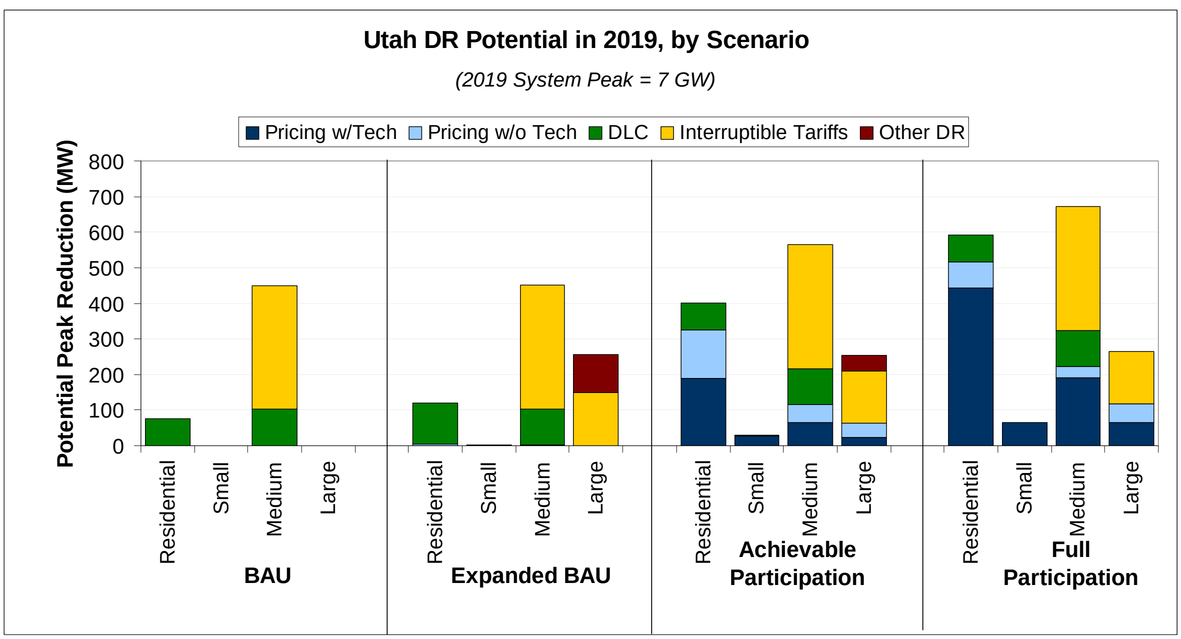
Key drivers of Utah's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and a fair amount of existing demand response. Enabling technologies are cost-effective for all customer classes. The state has a smaller-than-average Residential class and AMI deployment that potentially lags the national average, potentially leading to slower realized demand response potential. The state is characterized by a larger-than-average Medium C&I class that has significant amounts of existing demand response.

BAU: Utah's existing demand response is characterized by a large interruptible tariff program for the Medium C&I class. The rest of the existing demand response is through direct load control programs for the Residential and Medium C&I classes.

Expanded BAU: The majority of the growth in demand response potential is driven by interruptible tariffs and other demand response for the Large C&I class.

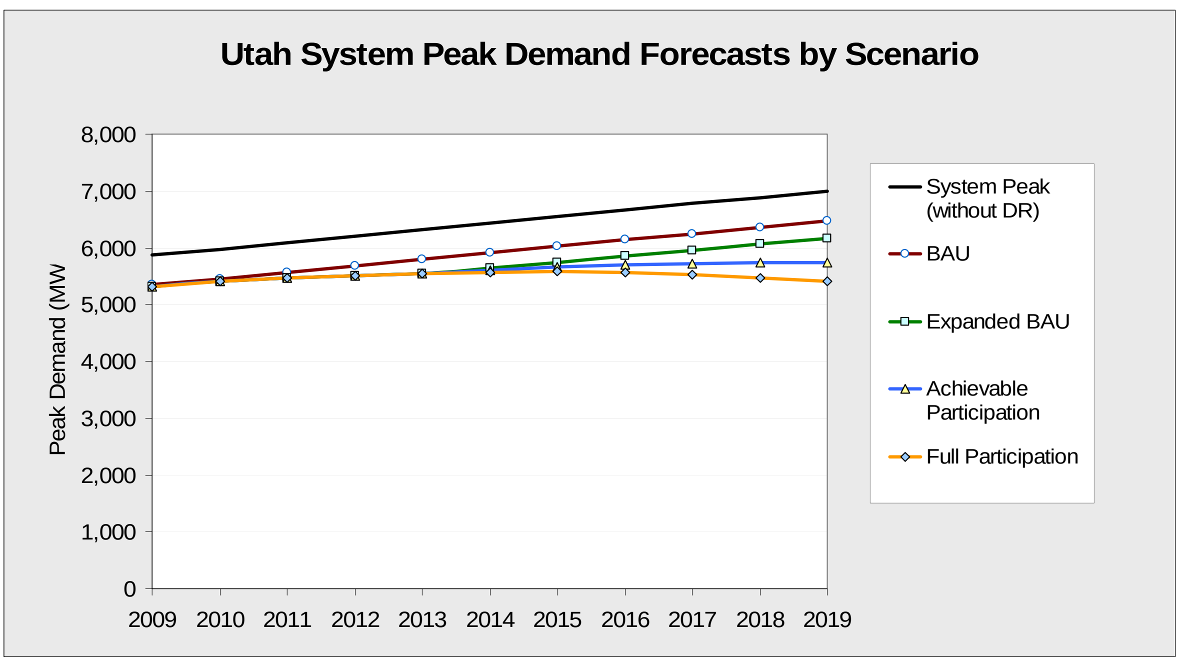
Achievable Participation: Demand response potential for this scenario comes mostly through the two dynamic pricing programs, with the majority utilizing enabling technologies. Enabling technologies are cost-effective for all customer classes.

Full Participation: Under this scenario, dynamic pricing with enabling technology continues to grow for all customer classes. Demand response potential for the Large C&I class decreases slightly, as customers switch from other demand response programs to the dynamic pricing programs, which have smaller per-customer impacts.



Total Potential Peak Reduction from Demand Response in Utah, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	0	0.0%	347	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	75	1.1%	0	0.0%	449	6.4%	0	0.0%	524	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	115	1.6%	2	0.0%	102	1.5%	0	0.0%	219	3.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	1.5%	107	1.5%
Total	119	1.7%	2	0.0%	451	6.4%	256	3.7%	828	11.8%
Achievable Participation										
Pricing with Technology	190	2.7%	27	0.4%	65	0.9%	22	0.3%	304	4.4%
Pricing without Technology	136	1.9%	2	0.0%	50	0.7%	40	0.6%	228	3.3%
Automated/Direct Load Control	75	1.1%	1	0.0%	102	1.5%	0	0.0%	178	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	43	0.6%	43	0.6%
Total	401	5.7%	30	0.4%	564	8.1%	254	3.6%	1,249	17.9%
Full Participation										
Pricing with Technology	444	6.3%	64	0.9%	191	2.7%	65	0.9%	763	10.9%
Pricing without Technology	72	1.0%	1	0.0%	32	0.5%	52	0.7%	158	2.3%
Automated/Direct Load Control	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	591	8.5%	65	0.9%	671	9.6%	266	3.8%	1,593	22.8%



Vermont State Profile

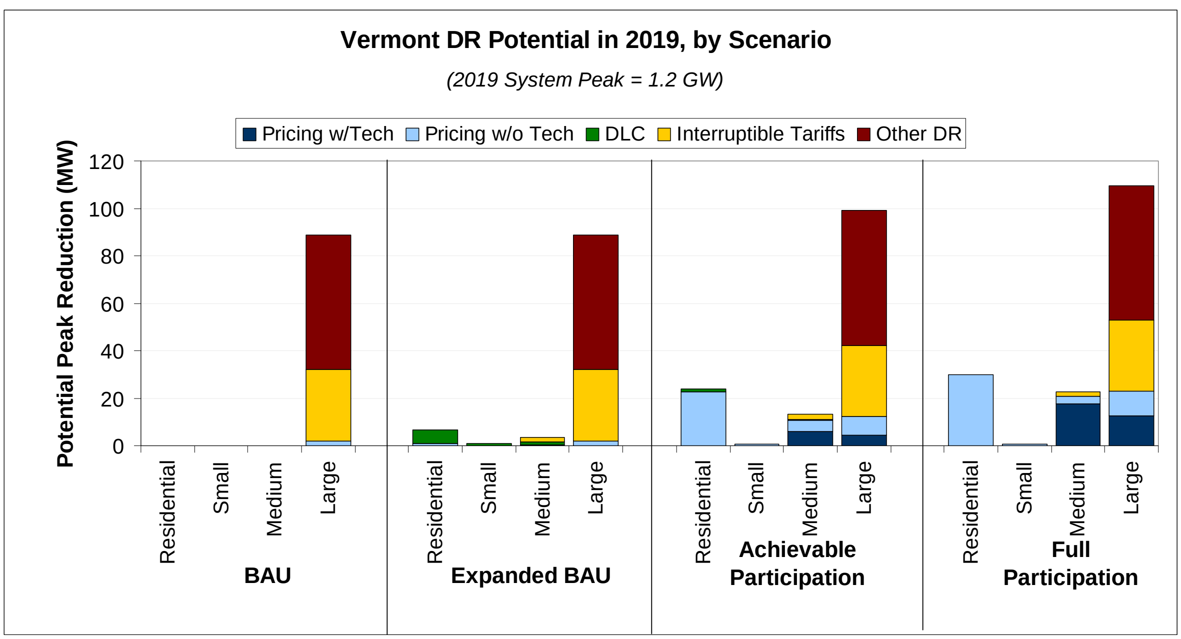
Key drivers of Vermont's demand response potential estimate include: significantly lower-than-average CAC saturation of 7 percent and enabling technologies that are cost-effective for only the Medium and Large C&I classes. Vermont's potential AMI deployment could lead the national average and result in faster realized demand response potential. However, the key driver of this state's demand response potential is very low residential CAC saturation and enabling technologies not being cost-effective for this class, leading to fairly small incremental potential relative to the BAU scenario.

BAU: Vermont has a large amount of existing demand response for the Large C&I class, through interruptible tariffs and other demand response.

Expanded BAU: Small demand response potential increases occur for the Large C&I class, through interruptible tariffs and other demand response. The Residential class shows a small amount of potential demand response through participation in DLC programs.

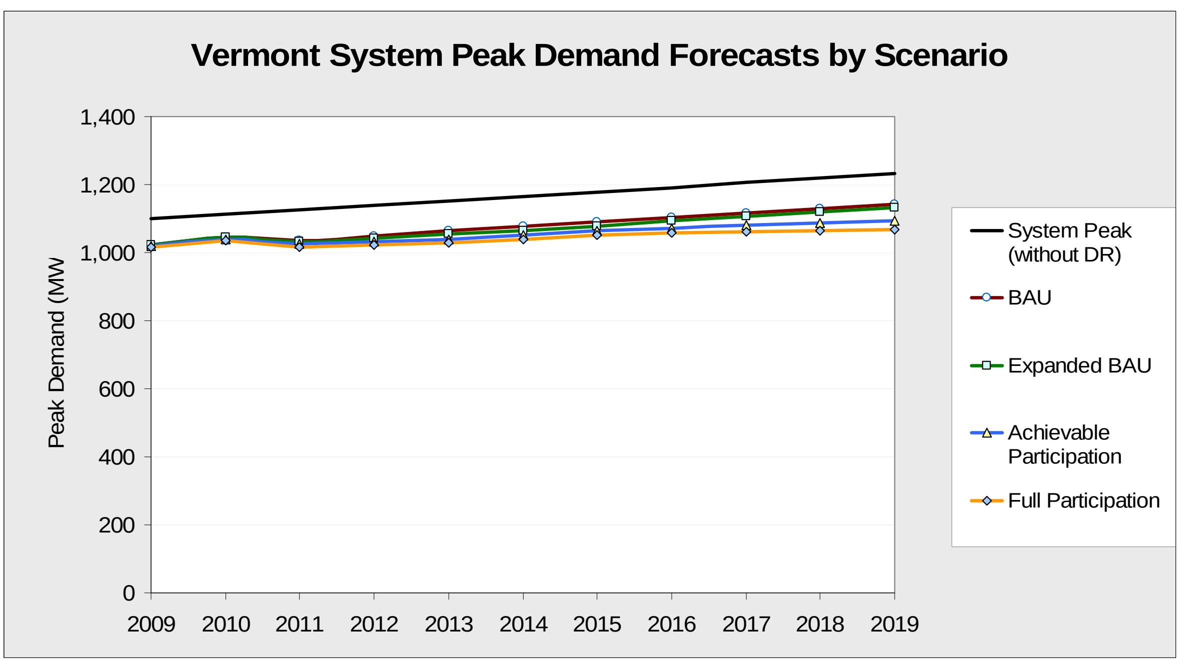
Achievable Participation: Residential and Medium and Large C&I classes show slight increases in dynamic pricing programs. The residential class has a much smaller-than-average demand response potential due to very low CAC saturation and enabling technologies not being cost-effective for this class.

Full Participation: Small increases in potential demand response result for all classes of customers. Overall the state shows a small amount incremental demand response potential driven primarily by low CAC saturation and enabling technologies not being cost-effective for both Residential and Small C&I classes.



Total Potential Peak Reduction from Demand Response in Vermont, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	2	0.2%	2	0.2%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	30	2.4%	30	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	0	0.0%	0	0.0%	0	0.0%	89	7.2%	89	7.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.1%	0	0.0%	0	0.0%	2	0.2%	3	0.3%
Automated/Direct Load Control	6	0.5%	1	0.1%	1	0.1%	0	0.0%	8	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	7	0.5%	1	0.1%	4	0.3%	89	7.2%	100	8.1%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	6	0.5%	4	0.4%	10	0.8%
Pricing without Technology	23	1.8%	1	0.0%	5	0.4%	8	0.6%	36	2.9%
Automated/Direct Load Control	1	0.1%	0	0.0%	0	0.0%	0	0.0%	2	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	24	1.9%	1	0.1%	13	1.1%	99	8.0%	137	11.1%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	18	1.4%	13	1.0%	30	2.5%
Pricing without Technology	30	2.4%	1	0.1%	3	0.3%	10	0.8%	44	3.6%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	30	2.4%	1	0.1%	23	1.8%	110	8.9%	163	13.2%



Virginia State Profile

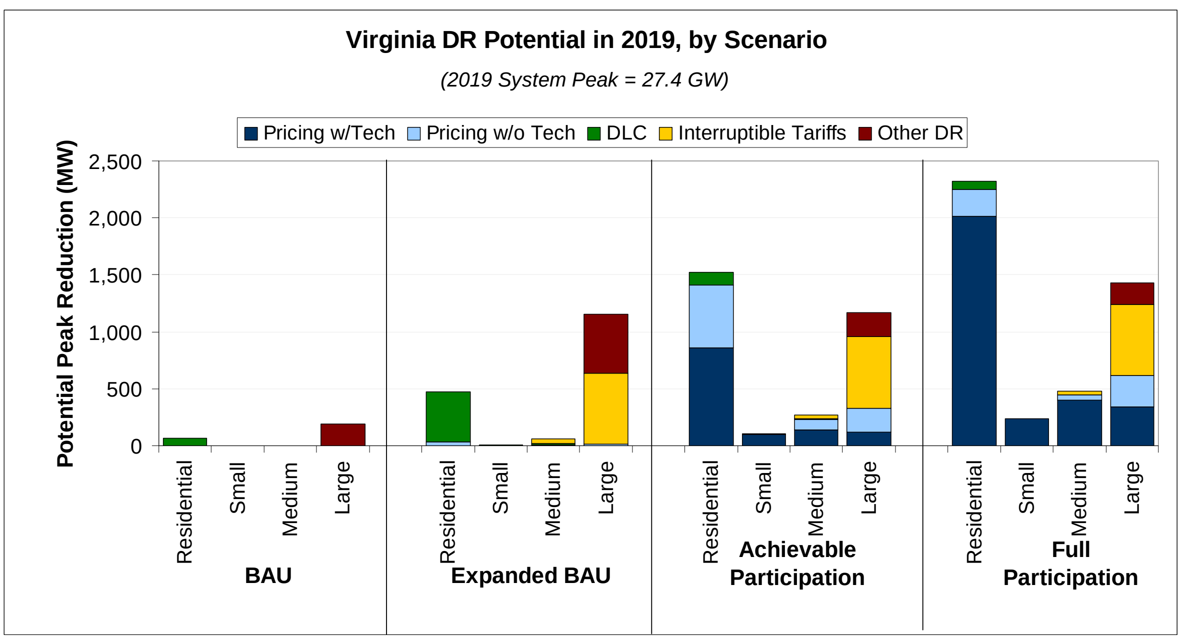
Key drivers of Virginia's demand response potential include lower-than-average residential CAC saturation (50 percent) and a small amount of existing demand response. Enabling technologies are cost-effective for all customer classes. Also, potential AMI deployment slightly leads the national average. A Large C&I class with a higher than average share of the system peak results in the class representing a significant amount of the state's overall demand response potential.

BAU: Virginia's small amount of existing demand response comes from DLC programs for residential customers and large C&I customer participation in 'Other DR' programs.

Expanded BAU: Growth in potential demand response is the result of higher than average peak demand in the large C&I class, resulting in large impacts from both interruptible tariffs and other demand response. The Residential class has a significant growth in load reduction coming from DLC programs.

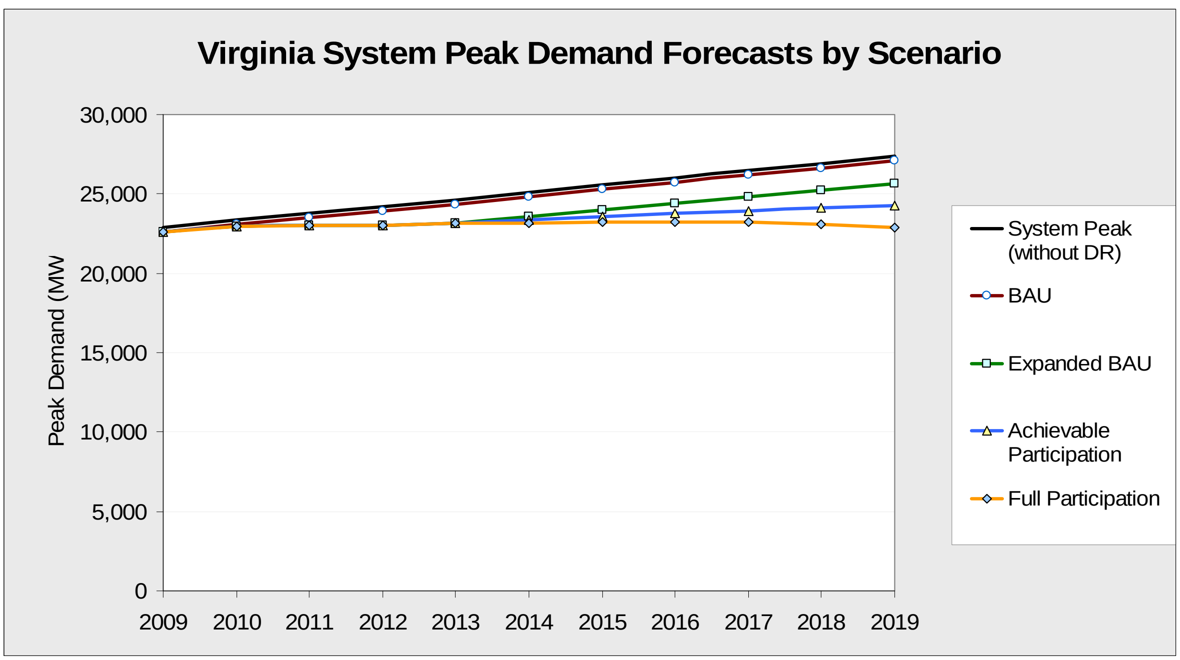
Achievable Participation: Enabling technologies are cost-effective for all customer classes, resulting in large dynamic pricing potential growth from these technologies. The Residential and Small C&I classes show customers enrolling in to the two dynamic pricing programs rather than in DLC programs.

Full Participation: The cost-effectiveness of enabling technology leads to significant growth in dynamic pricing for all classes, especially residential customers. The Residential and Large C&I classes account for most of the peak load, resulting in the majority of the demand response potential coming from these two classes.



Total Potential Peak Reduction from Demand Response in Virginia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	2	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	68	0.2%	0	0.0%	1	0.0%	191	0.7%	260	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	0	0.0%	7	0.0%	11	0.0%	50	0.2%
Automated/Direct Load Control	439	1.6%	8	0.0%	14	0.1%	0	0.0%	461	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	519	1.9%	519	1.9%
Total	471	1.7%	8	0.0%	57	0.2%	1,154	4.2%	1,691	6.2%
Achievable Participation										
Pricing with Technology	861	3.1%	100	0.4%	137	0.5%	117	0.4%	1,215	4.4%
Pricing without Technology	550	2.0%	5	0.0%	91	0.3%	213	0.8%	859	3.1%
Automated/Direct Load Control	112	0.4%	2	0.0%	6	0.0%	0	0.0%	120	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	212	0.8%	212	0.8%
Total	1,523	5.6%	107	0.4%	270	1.0%	1,167	4.3%	3,068	11.2%
Full Participation										
Pricing with Technology	2,015	7.4%	233	0.9%	400	1.5%	342	1.2%	2,990	10.9%
Pricing without Technology	238	0.9%	3	0.0%	44	0.2%	276	1.0%	560	2.0%
Automated/Direct Load Control	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	2,321	8.5%	236	0.9%	480	1.8%	1,431	5.2%	4,468	16.3%



Washington State Profile

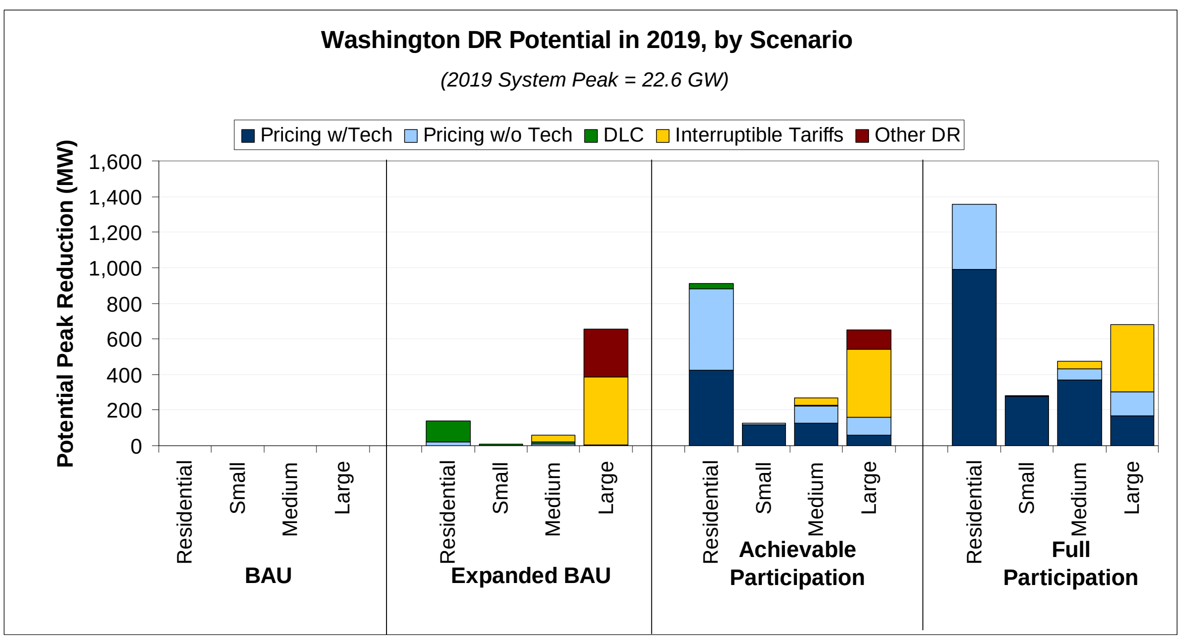
Key drivers of Washington's demand response potential estimate include: lower-than-average residential CAC saturation of 29 percent and no existing demand response. Enabling technologies are cost-effective for all classes. Also, the state's potential AMI deployment slightly leads the national average. Low CAC saturation and non-existent demand response are the key drivers for the state.

BAU: Currently, the state has no demand response. Historically, low energy prices and a surplus of hydro capacity have made demand response seemingly less attractive in this region.

Expanded BAU: The majority of the potential demand response is from Large C&I, through interruptible tariffs and other demand response. Some Residential demand response potential comes from DLC and dynamic pricing.

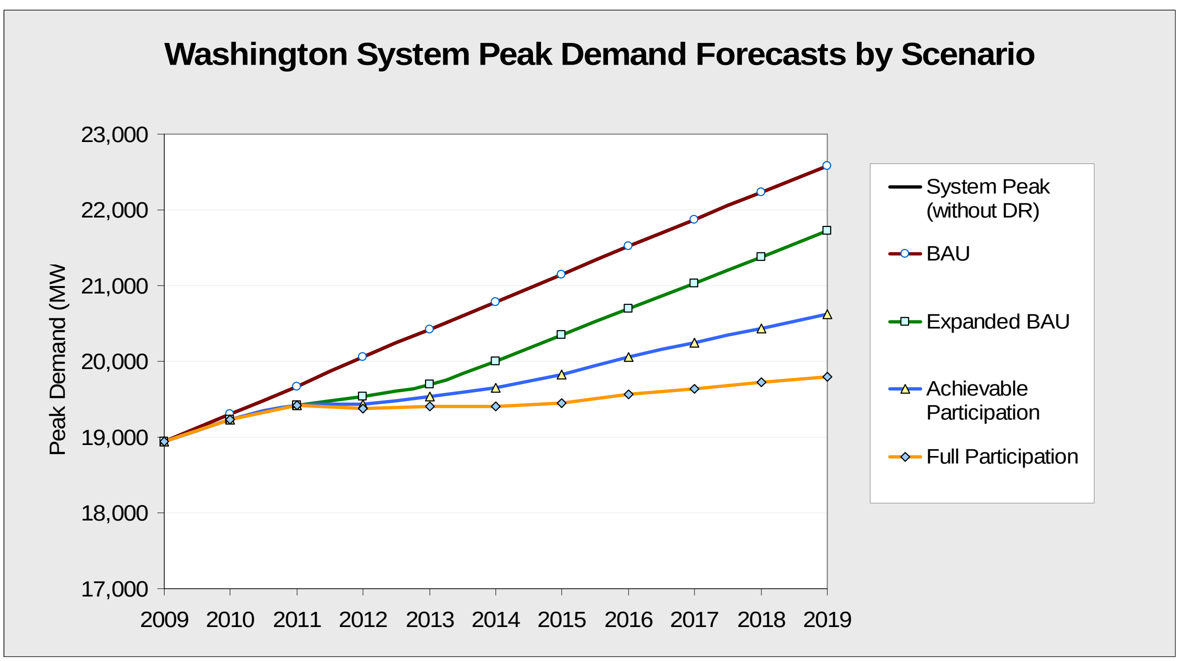
Achievable Participation: Demand response potential is driven by dynamic pricing with and without enabling technology. Many of the residential customers enrolled in DLC programs under the EBAU scenario would instead be expected to enroll in dynamic pricing with enabling technology under this scenario. Relative to the EBAU scenario, Large C&I customers would be enrolled more heavily in dynamic pricing than in interruptible tariff and other demand response programs.

Full Participation: Dynamic pricing programs dominate the demand response potential for this scenario, primarily those utilizing enabling technologies. The largest amount of load reduction can be potentially derived from residential customers. Enabling technologies are cost-effective for all customer classes. Some interruptible tariff demand response remains for both Medium and Large C&I.



Total Potential Peak Reduction from Demand Response in Washington, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	7	0.0%	5	0.0%	33	0.1%
Automated/Direct Load Control	118	0.5%	8	0.0%	12	0.1%	0	0.0%	138	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	139	0.6%	9	0.0%	60	0.3%	657	2.9%	864	3.8%
Achievable Participation										
Pricing with Technology	424	1.9%	118	0.5%	127	0.6%	57	0.3%	725	3.2%
Pricing without Technology	457	2.0%	8	0.0%	97	0.4%	104	0.5%	665	2.9%
Automated/Direct Load Control	30	0.1%	2	0.0%	5	0.0%	0	0.0%	37	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	111	0.5%	111	0.5%
Total	911	4.0%	128	0.6%	270	1.2%	652	2.9%	1,960	8.7%
Full Participation										
Pricing with Technology	991	4.4%	275	1.2%	370	1.6%	167	0.7%	1,803	8.0%
Pricing without Technology	365	1.6%	5	0.0%	62	0.3%	134	0.6%	567	2.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,357	6.0%	280	1.2%	473	2.1%	682	3.0%	2,792	12.4%



West Virginia State Profile

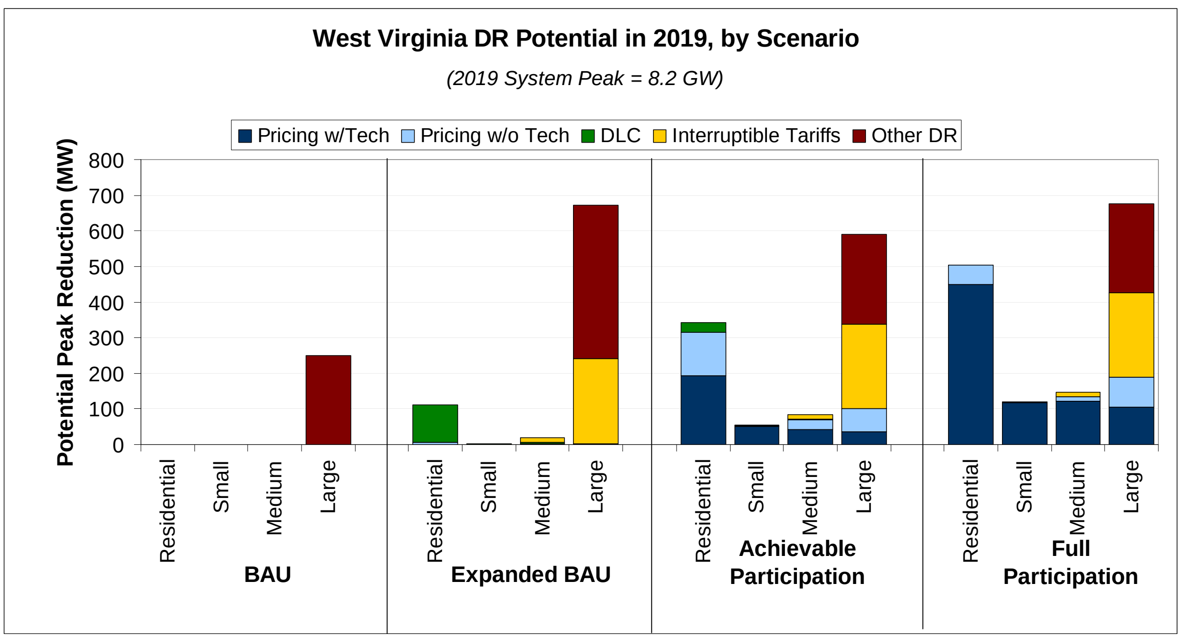
Key drivers of West Virginia's demand response potential estimate include: a CAC saturation of 50 percent and a moderate amount of existing demand response, and a larger-than-average Large C&I class (32%). Enabling technologies are cost-effective for all classes of customers. Also, potential AMI deployment slightly leads the national average. The larger-than-average Large C&I class, with significant existing demand response, is the primary driver for the state.

BAU: West Virginia has a significant amount of existing demand response for the Large C&I class, but none for the remaining classes.

Expanded BAU: Demand response potential comes primarily from the Residential and Large C&I classes. Residential demand response potential is in DLC programs, while the incremental increase in Large C&I potential is in interruptible tariff and 'Other DR' programs.

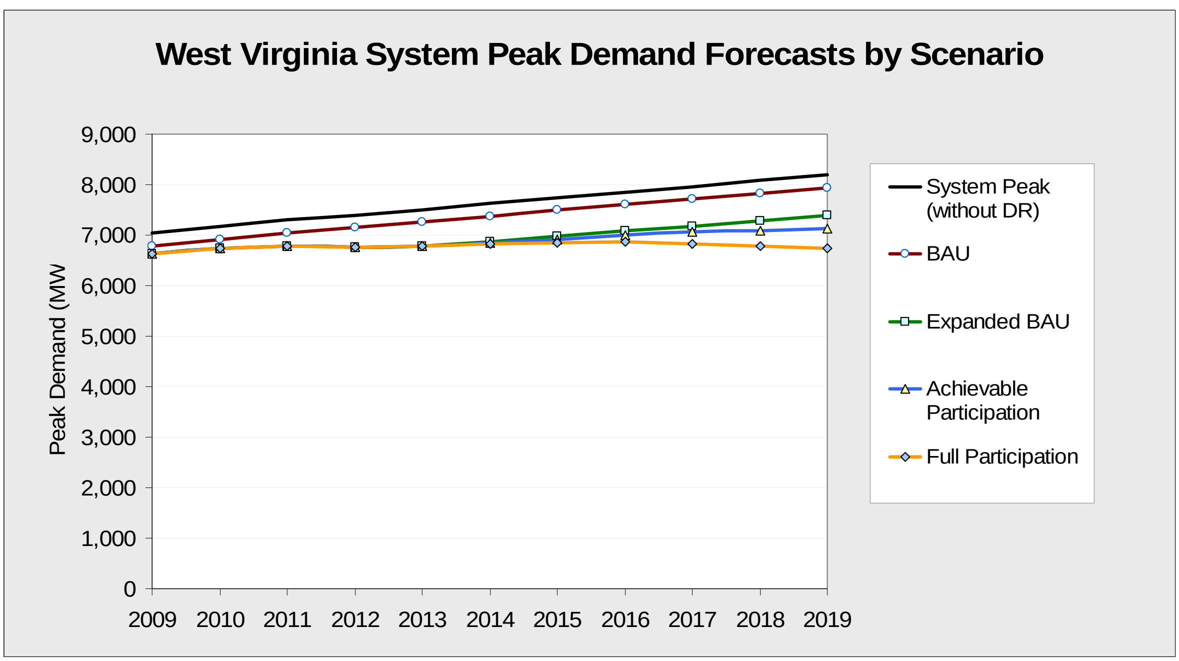
Achievable Participation: The main driver of demand response potential in this scenario is through dynamic pricing, with a significant amount of impact coming from the use of enabling technologies. Enabling technologies are cost-effective for all customer classes. The Large C&I class continues to dominate demand response potential because of its larger-than-average share of system peak load.

Full Participation: Demand response potential from dynamic pricing with enabling technology is largest under this scenario, with all customer classes exhibiting incremental increases in demand response potential relative to the other scenarios. For large C&I customers, potential from Interruptible tariffs and 'Other DR' programs continue to dominate.



Total Potential Peak Reduction from Demand Response in West Virginia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	7	0.1%	0	0.0%	2	0.0%	3	0.0%	12	0.1%
Automated/Direct Load Control	104	1.3%	3	0.0%	5	0.1%	0	0.0%	112	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	431	5.3%	431	5.3%
Total	111	1.4%	3	0.0%	19	0.2%	672	8.2%	806	9.8%
Achievable Participation										
Pricing with Technology	192	2.3%	50	0.6%	42	0.5%	36	0.4%	320	3.9%
Pricing without Technology	123	1.5%	3	0.0%	28	0.3%	65	0.8%	219	2.7%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	342	4.2%	54	0.7%	84	1.0%	589	7.2%	1,069	13.1%
Full Participation										
Pricing with Technology	450	5.5%	118	1.4%	121	1.5%	104	1.3%	794	9.7%
Pricing without Technology	54	0.7%	1	0.0%	13	0.2%	84	1.0%	153	1.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	504	6.2%	119	1.5%	147	1.8%	677	8.3%	1,448	17.7%



Wisconsin State Profile

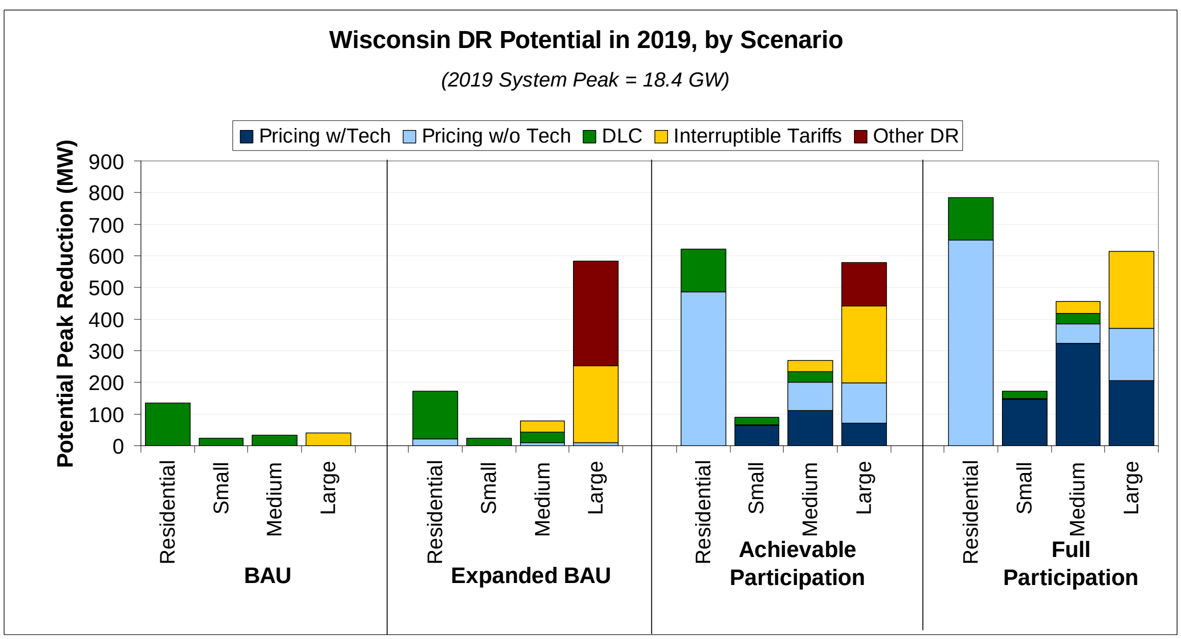
Key drivers of Wisconsin's demand response potential estimate include: a significant level of CAC saturation at 62 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes, but not for the Residential class. Also, a potential AMI deployment schedule that leads the national average could lead to faster realized demand response potential.

BAU: Wisconsin has existing demand response for Large C&I through an interruptible tariff program. DLC programs are in place for the remaining customer classes, with the Residential class exhibiting the largest impacts.

Expanded BAU: The Large C&I class exhibits significant demand response potential, which is driven by enrollment in new interruptible tariff and other demand response programs. Dynamic pricing plays a very small role relative to DLC impacts for Residential customers in this scenario

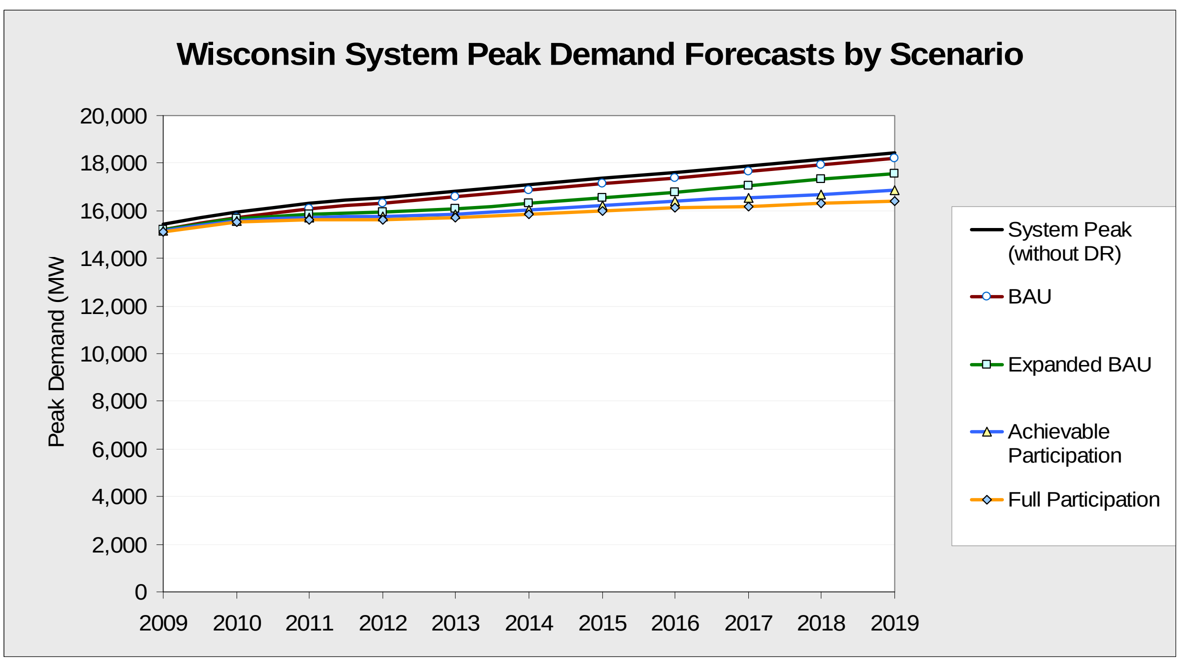
Achievable Participation: The majority of the incremental increase in demand response potential is due to dynamic pricing. Pricing with enabling technologies appears for all classes, except for the Residential class for which it is not cost effective. Still, the Residential class exhibits significant potential through participation in dynamic pricing programs without enabling technology. Total potential demand response decreases for the Large C&I class as a result of customers shifting to dynamic pricing programs, which produce smaller per-customer impacts.

Full Participation: Potential demand response continues to grow through increased enrollment in dynamic pricing programs. Large C&I customers are more heavily enrolled in dynamic pricing programs, slightly decreasing potential impacts from this class.



Total Potential Peak Reduction from Demand Response in Wisconsin, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	40	0.2%	40	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	135	0.7%	24	0.1%	33	0.2%	40	0.2%	231	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	9	0.0%	9	0.0%	39	0.2%
Automated/Direct Load Control	151	0.8%	24	0.1%	33	0.2%	0	0.0%	207	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	331	1.8%	331	1.8%
Total	172	0.9%	24	0.1%	79	0.4%	583	3.2%	858	4.7%
Achievable Participation										
Pricing with Technology	0	0.0%	63	0.3%	111	0.6%	70	0.4%	244	1.3%
Pricing without Technology	487	2.6%	4	0.0%	89	0.5%	128	0.7%	707	3.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.7%	137	0.7%
Total	621	3.4%	90	0.5%	270	1.5%	579	3.1%	1,560	8.5%
Full Participation										
Pricing with Technology	0	0.0%	147	0.8%	324	1.8%	205	1.1%	677	3.7%
Pricing without Technology	649	3.5%	2	0.0%	61	0.3%	166	0.9%	878	4.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	784	4.3%	173	0.9%	455	2.5%	615	3.3%	2,027	11.0%



Wyoming State Profile

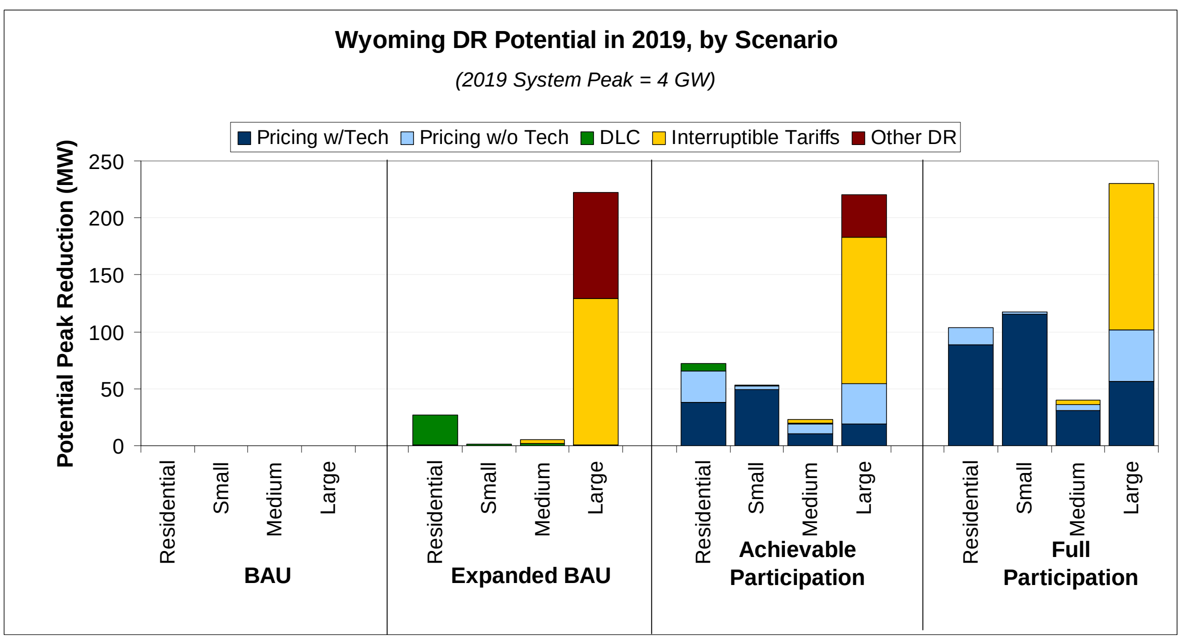
Key drivers of Wyoming's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and no existing demand response. Enabling technologies are cost-effective for all C&I classes and for residential customers. Also, potential AMI deployment that lags the national average could lead to slower realized demand response potential. The larger-than-average Large C&I class (36%) is the main driver of demand response in the state.

BAU: Currently, Wyoming has no existing demand response.

Expanded BAU: The Large C&I class represents the vast majority of demand response potential in the state, through enrollment in both interruptible tariff and other demand response programs. A moderate amount of demand response potential exists in residential DLC programs.

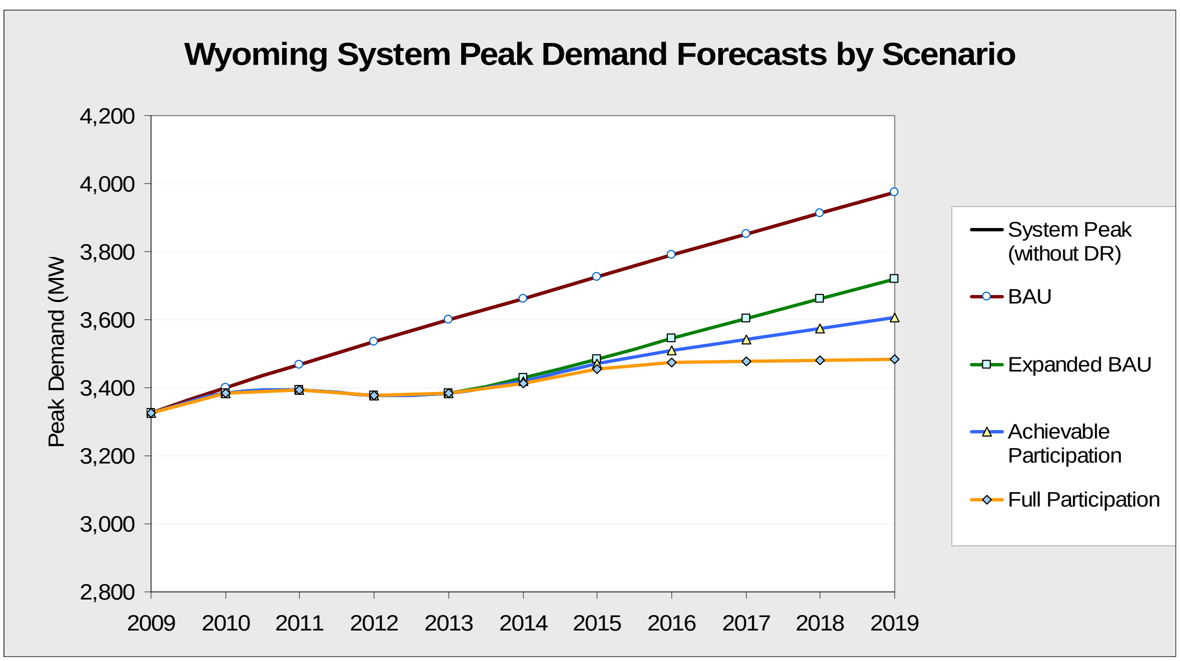
Achievable Participation: Impacts from dynamic pricing are relatively small compared to demand response potential in Other DR and Interruptible tariffs. All classes adopt enabling technologies. Total demand response potential decreases slightly for the Large C&I class due to customers shifting from other demand response programs in to pricing programs, which have smaller per- customer peak impacts.

Full Participation: Incremental demand response potential is highest for the residential, small, and medium C&I classes under this scenario. The Large C&I class drives total potential demand response in the state.



Total Potential Peak Reduction from Demand Response in Wyoming, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	1	0.0%	2	0.0%
Automated/Direct Load Control	26	0.7%	1	0.0%	1	0.0%	0	0.0%	29	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	2.3%	93	2.3%
Total	27	0.7%	1	0.0%	5	0.1%	222	5.6%	256	6.4%
Achievable Participation										
Pricing with Technology	38	0.9%	49	1.2%	11	0.3%	19	0.5%	117	2.9%
Pricing without Technology	28	0.7%	3	0.1%	8	0.2%	35	0.9%	74	1.9%
Automated/Direct Load Control	7	0.2%	0	0.0%	1	0.0%	0	0.0%	8	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	37	0.9%	37	0.9%
Total	72	1.8%	53	1.3%	23	0.6%	220	5.5%	368	9.3%
Full Participation										
Pricing with Technology	88	2.2%	115	2.9%	31	0.8%	56	1.4%	291	7.3%
Pricing without Technology	15	0.4%	2	0.1%	5	0.1%	45	1.1%	68	1.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	104	2.6%	117	3.0%	40	1.0%	230	5.8%	491	12.4%



APPENDIX B. LESSONS LEARNED IN DATA DEVELOPMENT

Development of state-level data for a bottom-up demand response potential assessment is a complex and challenging task. Data had to be developed for each state and D.C. by type of end-use customer, by type of demand response program, and by demand response potential estimation scenario, with an analysis timeframe spanning 2009-2019. The data development process drew upon information from a variety of different sources. There were challenges faced in compiling information, often not uniformly available across sources, to arrive at data required for potential estimation for all states. This section briefly discusses some of the challenges related to data development and scope for future improvements that are likely to address these challenges. It is intended to serve as a guide for making future updates to the analysis.

Nature of utility data reporting

Challenges

In developing some of the key data items required for potential estimation, utility data was aggregated to come up with state level estimates. Very often, it was found that for utility companies with service territories across multiple states, the reporting of data is at the operating company or entity level and is not disaggregated at the state level for these companies. This posed difficulties in directly aggregating the data to come up with state level estimates. Examples of data items where this difficulty was encountered are: state level estimates that show number of accounts by rate class, sales by rate class, and state peak load forecasts. In such cases, entity level data was disaggregated to the state based on other utility-level parameters reported by the operating company.

Scope for future improvements

Alteration of the nature of utility data reporting for those with service territories across multiple states is likely to address this problem. If utilities report data at the operating state level, instead of aggregate data at the entity level, it will make state level estimations easier.

Incomplete and non-uniform information availability for key data items

Challenges

Difficulties were posed by lack of availability of information related to key data items for potential estimation. Also, often when information was available, it was available from a wide variety of sources, and thus not uniformly characterized.

Examples of key data inputs where such challenges were faced are CAC saturation for residential customers and unit impact estimation for residential DLC programs. In the case of residential CAC saturation estimation across states, there were only very few states where information was available from statewide saturation surveys and other similar sources. Often, it was necessary to compile individual utility-level information and use that as the basis for arriving at state level estimates. There were a few states where data was available from housing surveys for certain metropolitan areas in the state. Also, data availability was for different years. Additionally, there were some states where it was difficult to source the data directly from any state level estimate. In such cases, regional values from appliance saturation surveys (e.g. Residential Appliance Saturation Survey conducted by EIA) were used to derive the state estimate.

Scope for future improvements

Development of comprehensive databases for key items with uniform level of information availability is likely to address this problem. For example, for residential CAC saturation data, a central repository of information from different sources to arrive at state level estimates could be compiled and periodically updated.

Data coverage by utility ownership

Challenges

During the process of developing aggregate state level estimates from utility data, there were difficulties due to lack of data from non-IOUs in the states. For example, FERC Form No.1 data reporting served as the basis for developing distribution of C&I customers by rate class (small, medium, and large).[71] But the FERC Form No. 1 data is available only for Investor-Owned Utilities (IOUs). In the absence of any such similar data reporting from non-IOUs, it was assumed that the distribution for IOUs was applicable to the non-IOUs in the state as well. Also, there were cases where data was not available for all IOUs in the state. Therefore, in all such cases, the estimations from the limited utility data set were assumed to be representative for the state.

Scope for future improvements

Systematic and uniform data collection from all utilities, across different ownership types, is likely to address this problem.

Level of data availability

Challenges

In developing some of the data items, it was necessary to apply regional estimates as proxy for state level data, wherever information at the state level was difficult to obtain. In cases where regional estimations could not be directly applied, the regional data was disaggregated to provide state level estimates based on related data available by state. For example, system peak load forecast from NERC was available only at the NERC regional level, which had to be disaggregated to arrive at state level system peak values. The methodological framework for doing that is described under the 'Data Development' section in the Appendix. Another example is application of regional estimates for growth rate in C&I accounts for all states in a particular census region, since variation by state for this particular item was difficult to estimate.

Scope for future improvements

Wherever information is available only at the regional level, future efforts could be directed towards systematically developing information at the state level by encouraging relevant agencies to report state-level information.

Difficulties related to data development by C&I rate classes

Challenges

A key challenge in developing data related to demand response potential estimation was in developing data for the three rate classes (small, medium, and large) for the C&I sector. Almost all key data inputs for potential estimation had to be developed at the rate class level. However, there was no source from where the information could be directly procured for the commercial rate classes. FERC Form No. 1 data, where individual utilities (IOUs only) report information by rate schedule, was used as the primary basis for developing data by rate class. But use of the FERC Form No. 1 data

[71] FERC Form-1 data was the best, most recently available information among possible data sources, including EIA, USDA Rural Utilities Service (RUS) and other entities that compile databases, etc.

for data estimation by rate class, in turn posed challenges that was inherent to the nature of the FERC Form No. 1 data availability and reporting requirements.

For example: FERC Form No.1 data is reported only by IOUs, and therefore the distribution of C&I customers by rate class applied only to IOUs. In the absence of similar data availability for non-IOUs, we applied the distribution from FERC Form No. 1 to all utilities in a state to arrive at the state level distribution, thereby assuming that the distribution of C&I customers by rate class for IOUs applies to non-IOU utilities as well. For utilities that operate in multiple states, it was necessary to assume that the same mix of C&I customers applies to all states in which a utility operates. In addition, FERC Form No. 1 data was not available for all IOUs across states.

Scope for future improvements

Data availability from utilities, which indicates the classification of customers by peak load, is likely to address this problem. This will enable categorizing C&I customers into different peak load size ranges. Also, information should be available from utilities across different ownership types.

APPENDIX C. DETAIL ON BARRIERS ANALYSIS

A number of barriers are preventing demand response from reaching its full potential in the United States. Some of these barriers are regulatory in nature, stemming from existing policies and practices that are not designed to facilitate the use of demand response as a resource. These barriers exist in both wholesale and retail markets. Other barriers are economic in nature. Finally, certain technological limitations are also standing in the way. In total, there are some 24 barriers to demand response. This appendix includes a discussion of existing demand response barriers, organized into four categories: (1) Regulatory barriers (general, retail and wholesale), (2) economic barriers, (3) technological barriers, and (4) other barriers.

Regulatory Barriers

Regulatory barriers are impediments to demand response caused by a particular regulatory regime, market design, market rules, or the demand response programs themselves.[72] Regulatory barriers constitute the largest group of barriers in this analysis. Below is a summary of the major regulatory barriers, divided into three sub-categories: general, retail-level, and wholesale-level.

General Regulatory Barriers

Retail and Wholesale Price Disconnect

Principal among the regulatory barriers is the lack of a direct connection between retail and wholesale electricity prices. This refers specifically to the lack of dynamic pricing in retail markets.[73] Simply put, most of today's retail tariffs do not reflect the time variation in the cost of electricity supply. As a result, customers are not provided with the appropriate price signals to promote efficient electricity consumption and may over-consume power during expensive peak periods and under-consume power during inexpensive off-peak periods.

Retail customers are essentially provided a full requirements contract in which suppliers bear all the volumetric and price risk. Such fully hedged rates dominate the marketplace, particularly for residential customers. Dynamic pricing rates are not provided as universal service rates nor are they offered as the default service to residential customers of any utility in the US. Indeed, in most parts of the country, dynamic pricing rates are not even available on an elective basis to residential customers. One often cited reason is that the necessary metering technology is not widely deployed to this class of customers.[74] But there are other reasons as well, including a perception that customers do not like price volatility.

While it is true that time-of-use (TOU) rates are the default rate for large commercial and industrial (C&I) customers at some utilities, these rates do not fully reflect the dynamics of power markets or electricity supply costs. Larger C&I customers in restructured power markets such as Connecticut, Illinois, Maryland, Michigan, New England, New Jersey and New York commonly face default real-time pricing

[72] Barriers related to customer attitudes, which sometimes fall into this category, are addressed in the "Other Barriers" section.

[73] In this discussion, we distinguish between two types of time-varying pricing, dynamic and static. Traditional TOU rates, in which prices typically vary by rate period, day of week and season, have higher prices during all peak rate periods and lower prices during all off-peak rate periods. Since TOU price levels and the timing of the periods are known with certainty, they are static time varying prices. Dynamic prices have some degree of uncertainty associated with them, either concerning when certain prices are in effect, or what price levels are in each time period. Critical peak pricing is a dynamic rate in which the prices on certain days are known ahead of time, but the days on which those prices occur are not known until the day before or day of. Real time pricing is another form of dynamic pricing, in which prices in effect in each hour are not known ahead of time.

[74] However, time-varying rates are an option for some residential customers. For example, Arizona Public Service and Salt River Project offer widely-adopted residential TOU rates. Georgia Power offers a residential critical peak pricing (CPP) rate.

(RTP) rates.[75] However, even these rates typically do not reflect the full time variation in supply costs, as they do not incorporate long-run capacity costs in peak period prices.

In July 2008, there was a decision by the California Public Utilities Commission (CPUC) to make dynamic pricing the default rate offering for all customer classes in the state.[76,77]

Measurement and Verification (M&V) Challenges

To accurately assess the benefits of demand response, it is necessary to have standardized practices for quantifying demand reductions. Currently, these practices are often unclear, inaccurate, and inconsistent across utilities, states and ISOs. This has negative impacts on three specific areas: demand response contract settlement, operational planning, and long term resource planning. To date, the focus has generally been on developing M&V practices for settlement purposes, and determining the appropriate level of demand response that should be compensated. However, operational and long term planning have not been key factors in that development process. Both deserve more attention. Operational methods need to be developed to better predict the short term (i.e. day-ahead) impacts of demand response resources. M&V is important to the long-term planning process to the extent that it will influence generation, transmission, and distribution investment decisions.

In April of this year, the California Public Utilities Commission adopted a set of load impact protocols that California's IOUs must use to develop both ex post and ex ante impact estimates for all of their demand response programs.[78] These protocols are designed primarily to support long term resource planning and to asses progress toward meeting resource adequacy requirements in California. They set minimum requirements in terms of the type of information that must be provided for each demand response resource (e.g., impact estimates for each hour on a typical event day) and the factors that must be taken into consideration when developing impact estimates (e.g., ex ante impact estimates must be developed for weather conditions representing 1-in-2 and 1-in-10 weather years). Each year, California's utilities are required to produce ex post impact estimates for each program for the prior year and to update ex ante impact estimates for the subsequent five year period. The protocols were used by each of California's three major IOUs in their recent demand response program applications.[79] In conjunction with these applications, thousands of Excel spreadsheets were filed with the CPUC showing ex post and ex ante impact estimates for roughly a dozen different types of demand response resources and various customer segments. These tables are good examples of the type of information resource that can be developed in the industry when regulators and other stakeholders establish good M&V standards and protocols.

Another example of useful work in the M&V area is represented by recent work being done by the North American Electric Reliability Corporation (NERC) initiated an effort to improve its data collection process for evaluating existing demand response resources at the NERC region level.[80] The effort will specifically focus on expanding and more accurately defining the sources of demand response that are reported, as well as improving the methodology that utilities will use to collect and report data on their demand-side management (DSM) programs.

Much of NERC's initiative will be coordinated with work that is being done by the North American Energy Standards Board (NAESB) to create M&V standards for wholesale markets. This work will focus

[75] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.

[76] Decision adopting dynamic pricing timetable and rate design guidance for Pacific Gas & Electric Company, D. 08-07-045, July 31, 2008.

[77] The residential class is an exception, where legislation (Assembly Bill 1X) freezes the rates for 130 percent of baseline usage until the power purchase contracts that were signed by the state during the energy crisis of 2001 have expired.

[78] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

[79] See, for example, Stephen S. George, Josh Bode and Josh Schellenberg. Load Impact Estimates for Southern California Edison's Demand Response Program Portfolio, September 25, 2008. Filed in conjunction with SCE's Demand Response Program Application for 2009-2011.

[80] NERC, "Data Collection for Demand-Side Management for Quantifying Its Influence on Reliability: Results and Recommendations," December 2007.

on developing voluntary demand response standards that would have both wholesale and retail components.[81] Meetings are currently being held to bring industry leaders together to focus on specific recommendations for these standards.

A related barrier to measurement and verification – disagreement on cost-effectiveness analysis – is discussed in the "Retail Regulatory Barriers" section.

Shared State and Federal Jurisdiction

Another barrier to demand response is that of shared state and federal jurisdictions. State commissions regulate retail sales in their own jurisdictions, but do not regulate wholesale markets or transmission. FERC, on the other hand, regulates wholesale markets, but has no direct control over retail tariffs.[82] To the extent that these regulatory bodies have conflicting policy objectives, lack of a coordinated effort can pose a serious barrier to demand response. This concept can also be extended to include state-level interactions with RTOs and ISOs, where a coordinated effort across multiple states is needed to maximize the reliability value of utility-operated demand response programs. At the recent FERC Technical Conference on demand response in organized markets, a representative from Dominion Electric Cooperative cited this as a major barrier to their demand response efforts, specifically indicating that no consensus for the demand response "end game" has been reached, and that a single roadmap is needed to move forward and address the "intertwining between federal and state jurisdictions."[83]

Perception of Gaming

The perception that some participants in demand response programs will "game" the system has become a barrier for demand response programs that require the estimation of a participant's baseline consumption level. This can apply at both the wholesale and retail levels. For example a large industrial customer that is bidding demand reductions into a wholesale demand response program would have the incentive to increase its baseline in order to appear to provide larger demand reductions. A similar incentive would exist in retail programs such as peak-time rebates (PTR) for residential customers, where customers are paid based on how much they lower their usage with reference to an unobserved baseline. RTOs such as PJM are currently examining methods for reducing the ability of participants to artificially inflate their baselines.

Considerable attention was paid to this topic at the FERC Technical Conference on demand response in organized markets. Participants identified ongoing efforts to address the baseline gaming issue in both California and PJM. Further, ISO New England (ISO-NE) and New York ISO (NYISO) were identified as discussing a new proposed method of estimating baselines.[84] A number of suggestions were proposed for addressing this issue, including using different estimation methods for different customer types (e.g., making a distinction between weather-responsive and non-weather-responsive customers) and relying on an entire season of historical load data.[85]

Lack of Sufficient Real Time Information Sharing Between ISOs and Utilities

When responding to an emergency event on the system, ISOs are not always aware of how much of a particular demand response resource is available, or even when it has been called by the utilities. This lack of real time communication among ISOs, utilities, and aggregators limits the value of demand response to ISOs for operational planning purposes and potentially leaves valuable demand response resources sitting idle at a time when they are needed most. According to the FERC 2007 Demand Response Assessment, this was found to be an issue during heat waves in the summer of summer 2006 in both California and the Midwest ISO.[86]

[81] NAESB comments to FERC Technical Conference on Demand Response in Wholesale Markets, April 2007.
[82] An exception to this is ERCOT which is not subject to FERC jurisdiction because it is wholly contained within the state of Texas and only has asynchronous transmission connections with other states.
[83] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 136.
[84] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 17.
[85] *Ibid.*, p. 65.
[86] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.

Lack of Reliability and Predictability of Demand Response

For demand response to be valuable as a resource, it must be dependable and predictable. In other words, when a program operator "pushes the button" they need to know that they will get the amount of demand reduction that they are expecting. Today, there are concerns that demand response is not as reliable as a supply-side resource. This is largely due to a lack of historical evidence (or at least data) showing consistent impacts from demand response resources or estimates of what demand response resources will provide under various event conditions. This is particularly true for economic programs such as dynamic pricing, for which there have been many robust pilots that have quantified the impacts, but for which there is not yet a significant history of full scale deployment. This shortcoming should decline over time as more empirical evidence is developed and made available to the industry, such as the load impacts recently filed by California's IOUs that were referenced above.

At the wholesale level, in ISO-NE the results of a small pilot showed that the aggregate performance of demand response assets varied from 30 percent to 90 percent of the expected reduction from one demand response event to the next. Efforts are underway to expand the size of these pilots and develop more robust results.[87]

This barrier may be derived partly from the voluntary nature or many demand response programs. These programs do not require that enrolled customers provide peak reductions during critical events – they simply offer payments if the customers respond. By putting control of the program in the hands of the participant, there is no guarantee that the load reduction will be provided. However, a noteworthy counterargument to be made is that while a specific customer may or may not respond to an event on any given day, what matters is the aggregate response from all customers enrolled in a program. To the extent that this aggregate number is statistically predictable, then the program does serve as a reliable resource.

Retail Regulatory Barriers

Policy Restrictions on Demand Response

One of the single biggest barriers to demand response at the retail level is policy restrictions that have the unintended consequence of limiting or even prohibiting certain types of demand response. This most commonly occurs in the form of restrictions on rate design. One such example is California's Assembly Bill 1X, which has been interpreted by the CPUC as a rate freeze for the first two tiers of each residential customer's usage.[88] This effectively prohibits utilities from offering time-of-use or dynamic rates to residential customers on a default basis because they would raise prices in the first two tiers for peak periods. Because of this constraint, the utilities in California have proposed the use of Peak Time Rebates (PTR) for all residential customers. A PTR is a "carrot only," pay for performance program that pays customers a certain amount for each kWh reduced during peak periods on high demand days.

Utilities in New York currently face a similar problem. In New York, state law prohibits utilities from placing residential customers on mandatory or default time-of-use-rates, forcing them to provide these rates on an opt-in basis and effectively reducing the participation rate. In Maine, current restrictions on the form of Standard Offer Service that can be offered through regulated utilities significantly inhibit (some have argued prevent) the ability to offer peak time rebates or critical peak prices to customers that do not switch to competitive suppliers.

Ineffective Demand Response Program Design

Ineffective demand response program design can lead to low enrollment and/or low impacts for demand response programs. One such example is the Puget Sound TOU pricing pilot of 2002.[89] The pilot tested a TOU rate with a very small peak-to-off peak price differential. Due to this design, customers who shifted significant amounts of load from the peak period to the off peak period saw only small bill savings, and

[87] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 132.
[88] See, for example, CPUC Decision 04-04-020.
[89] Ahmad Faruqui and Stephen S. George, "Demise of PSE's TOU Program Imparts Lessons," Electric Light and Power, January 2003.

lost interest in participating as a result. As large numbers of customers exited the program, it created a public relations problem for the utility and the program was shut down.

Another characteristic of poor demand response program design is a short expected program life. When programs are implemented as trial programs, there can be hesitancy on the part of customers to invest in the equipment, systems, and training necessary to make the program a success. Other characteristics of the program must also be designed with the intent to balance operational needs with customer ability to respond. For example, if the lead time to respond to demand response events is short (e.g., day-of) and customers are not equipped with enabling technologies to automate load reductions, then their ability to respond will be limited.[90] The duration and frequency of demand response events will also influence the participation level of customers. Ultimately, demand response programs must be designed to find an attractive balance between the reward that customers receive and the inconvenience (or cost) that they incur by participating.

Other examples of ineffective program design include disconnects between event triggers and operational needs (e.g., calling CPP events too late in the day to influence day ahead bids and dispatch schedules), telemetry requirements that may not be relevant for demand resources, and paying incentives that are significantly lower than avoided capacity costs and therefore limiting program participation.

<u>Financial Disincentives for Utilities</u>

Without certain regulatory mechanisms in place, utilities generally have a disincentive to pursue programs that will reduce sales. While this problem is most pronounced with energy efficiency programs, it is also present with programs to encourage demand response. Ultimately, the reduction in sales that results from demand response programs will cause the utility to fall short of recovering the fixed revenue requirement that would otherwise be recovered in the absence of the sales reduction.

The lost revenue disincentive associated with demand response is particularly relevant with respect to TOU rates and dynamic pricing. These rates are designed to be revenue neutral assuming no change in the pattern of energy use, but they ultimately are expected to change the pattern of use. If customers are on TOU pricing, revenue is expected to fall as a result of the change in consumption. With dynamic pricing there is also an issue that a significant amount of revenue is being collected through prices during the peak periods of a few "critical" days. To the extent that critical events are not triggered on those days and the critical prices are not dispatched, the utility would fall short of its revenue requirement.

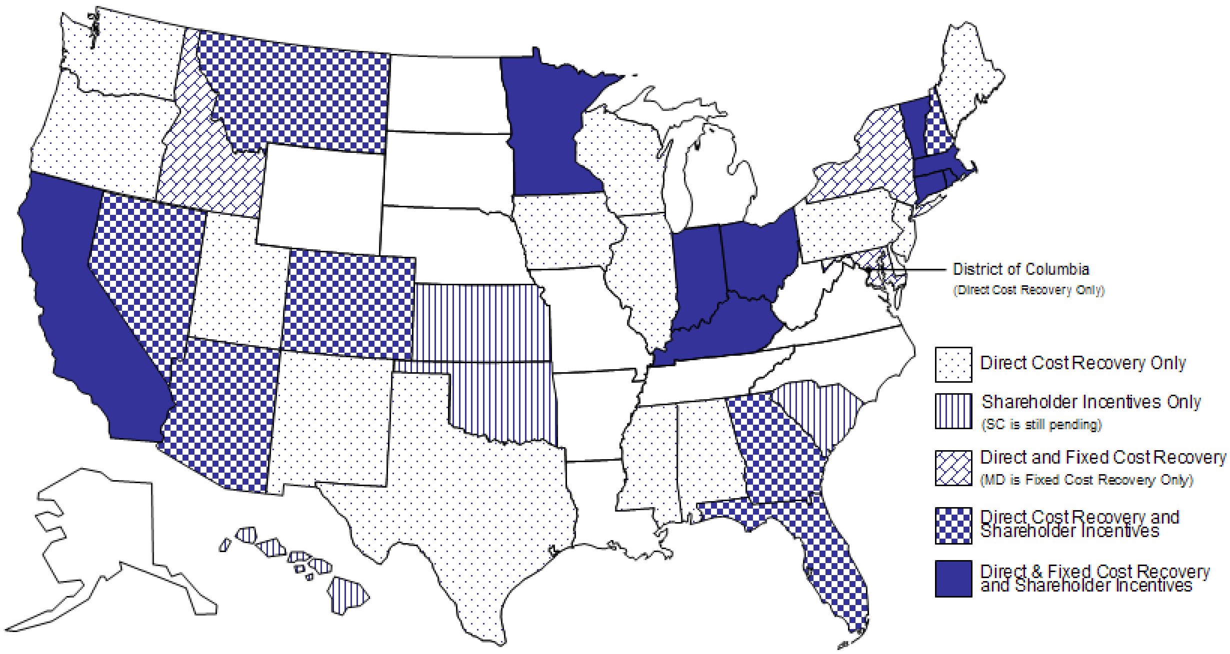
To address this, some states have regulatory incentives in place to either remove this disincentive, or provide a financial incentive to pursue demand-side programs. The regulatory mechanisms fall into three categories:

- Direct cost recovery: This is the most common form of regulatory incentive. It allows utilities to recover the DSM program implementation costs in a timely manner. It is also the weakest of the three mechanisms for promoting DSM.
- Fixed cost recovery: This category includes "decoupling." Essentially, the link between sales and revenue is removed and utilities are allowed to true-up their rates between rate cases to recover the lost revenues associated with the decreased electricity sales.
- Shareholder incentives: This includes all models that are designed to provide utilities with a financial incentive above and beyond their normal rate of return on investments. A recent example is California's Shared Savings model, which shares the net benefits of DSM impacts between the utility and the consumer. The Duke Save-a-Watt model is another such example, although it has not yet been adopted.

[90] This has recently been observed in the ComEd residential RTP program.

Many states have adopted various forms of these regulatory incentive mechanisms, as illustrated in Figure C-1.

Figure C-1: Regulatory Mechanisms for Promoting DSM at Electric Utilities



Source: National Action Plan for Energy Efficiency Leadership Group, "Aligning Utility Incentives with Investment in Energy Efficiency," November 2007. Includes additional information to reflect recent regulatory changes. Note that Direct Cost Recovery mechanisms include: rate case, system benefits charges, and tariff rider/surcharges; Fixed Cost Recovery mechanisms include: decoupling and lost revenue adjustment mechanisms. Shareholder Incentives include performance incentives.

However, it is important to note that some of these regulatory mechanisms only apply to energy efficiency measures and do not include impacts from demand response.

Disagreement on Cost-Effectiveness Analysis

Accurate estimation of the financial value of peak reductions induced by demand response is essential to understanding and quantifying demand response benefits. Currently, there is significant disagreement as to what should and should not be included in such benefits assessments. For example, wholesale electricity price reductions are widely cited as a benefit of increased demand response efforts. However, as this is often considered a short-term benefit, it is unclear as to the time horizon over which these benefits should be included. Further, others argue that this benefit is simply a transfer of wealth from generators to consumers and should not be included as a benefit of demand response at all. This was the topic of a recent workshop sponsored by the Mid-Atlantic Distributed Resources Initiative (MADRI).[91]

In addition to which types of benefits should be included in an accurate cost effectiveness assessment, there are also issues concerning the valuation of avoided costs. For example, one major source of financial benefit from demand response is avoided generating capacity cost. However, there is significant disagreement over what should be used as the avoided capacity price. Utilities in California have agreed that the full cost of a peaking plant should be derated to account for revenues that it will earn through sales to the market, as well as to account for a lack of certainty that a demand response program will effectively reduce demand at the time of system peak. However, there is disagreement as to how this adjustment should be calculated. Further disagreement arises as to the level of avoided transmission and distribution (T&D) capacity that should be accounted for by demand response. Some cost-effectiveness tests have been developed in California, although no standard has yet been set. The issue is being

[91] Newell, Sam and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

examined in an ongoing CPUC proceeding (R.07-01-041). Standards for cost effectiveness are also the topic of the previously mentioned NAESB effort in this area.[92]

Lack of Retail Competition

According to some analysts, lack of retail competition is another barrier to demand response. In regions without significant competition at the retail level, providers of demand response programs may not have the same incentive to minimize costs and offer services that are as robust as if there were firms offering competing services. Increased competition from third party aggregators could be a way of introducing innovative program designs and marketing channels. In fact, FERC issued its Wholesale Competition Final Rule (or Order No. 719) which addresses this issue.[93] Order No. 719 requires all RTOs and ISOs to permit aggregators of retail customers to bid demand response on behalf of retail customers directly into the organized energy market, unless the law or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[94]

Wholesale Regulatory Barriers

Market Structures Oriented Toward Accommodating Supply Side Resources

Supply-centric market structures limit the participation of demand response resources in several ways. These limitations can include demand response not being allowed to participate in certain markets or overly restrictive market rules that make participation prohibitively expensive or otherwise extremely difficult, restrictions on who can bid demand response into the market, restrictions on suppliers of standard offer service to provide demand response, and lack of a capacity payment for demand response.

Wholesale electricity markets have reliability rules that are specific to the limitations of generators, but not necessarily to demand response resources. For example, rules such as minimum run times would apply to supply side resources, but there are not also maximum run time rules(bidding parameters, as that term is used in Order No. 719), which would accommodate demand response resources.[95] Accommodating these limitations and developing more robust market rules could increase demand response participation in wholesale markets. FERC addressed this issue in its Order No. 719 in requiring each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[96] Indeed, growing participation of demand response resources in ancillary services markets has been observed, particularly in ISO-NE.[97]

There is also sometimes confusion as to who can actually participate in wholesale markets as a provider of demand response. Andrew Ott of PJM recently indicated that this is a particular barrier to demand response in PJM. Specifically, he noted that "there's really no established process in the PJM tariff today to allow us to determine whether end users within its jurisdiction in certain customer classes should or should not be able to participate significantly in PJM's wholesale market. There's ambiguity."[98]

There are other markets where demand response is not allowed to compete at all.[99] For example, demand response is not allowed to bid in the operating reserve markets of ISO-NE. This was cited as a major

[92] Draft Agenda to NAESB DSM-EE meeting on October 3, 2008.

[93] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008), p. 3 and 154-164.

[94] Id. at p. 3 and 154-164.

[95] FERC, "2006 Assessment of Demand Response and Advanced Metering," August 2006, p. 117 - 118.

[96] Order No. 719, FERC Stats. & Regs. ¶ 61,071, p. 3 and 47.

[97] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.

[98] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 127.

[99] A summary of the markets in which demand response can and cannot compete is provided in the Policy Options section of this memorandum.

barrier to demand response adoption in wholesale markets by Eric Woychik of Comverge in the FERC Technical Conference on demand response in organized markets.[100]

The full value of demand response should be recognized. For example, demand response has an "option" value in the sense that, regardless of whether it is used, it can be depended upon for reliability and planning purposes. As a result, it should be allowed to compete with supply side resources in planning processes. In regions without a capacity market, or where demand response cannot participate in capacity markets, this can pose a challenge and lead to undervaluing the resource. ISO-NE is an example of a market that allows demand response to compete in its Forward Capacity Market (FCM) up to a limit. In the past four auctions, 2,500 MW of demand response have cleared the market representing roughly nine percent of the resource base in 2010.[101] In fact, Henry Yoshimura of ISO-NE recently indicated that "demand resources are no longer facing barriers in the capacity markets."[102] PJM also allows demand response in its capacity market, and 7,047 MW of demand response cleared in its auction held for 2012/2013.[103]

Economic Barriers

Economic barriers refer to situations where the financial incentive for utilities or aggregators to offer demand response programs, and for customers to pursue these programs, is limited. These barriers are described below.

Inaccurate Price Signals

Inaccurate prices are a barrier to programs in which demand responds to price signals. An inaccurate price could cause a resource to reduce demand when the underlying energy value is low, or raise it when the value is high, which would impair the economic efficiency of the energy market. FERC recognized in Order No. 719 that prices that fail to accurately reflect the value of energy may inhibit and deter entry of demand response and thwart innovation.[104]

Lack of Sufficient Financial Incentives to Induce Participation

For some customers, demand response programs may not provide a sufficient financial incentive to participate. If customers place a high enough value on being able to consume as much electricity as they want, when they want it, then the financial incentives to participate in demand response programs may not be large enough to justify their participation. Of course, higher payments are likely to result in increased participation. For example, Southern California Edison (SCE) offers one of the most financially attractive residential air conditioner direct load control (DLC) programs, with an annual payment of between $100 and $200[105] for participants who sign up for 100% cycling and unlimited interruptions. This is likely one of the factors that has led to enrollment of over 325,000 residential customers in SCE's program, with almost 90% of them selecting the 100% cycling option.

Additionally, dynamic rates by definition will result in some customers experiencing bill increases due to their peakier-than-average consumption patterns, and these customers may not opt-in to such a rate if it is only offered on a voluntary basis. However, when accounting for moderate shifting of load from peak to off-peak periods, such rates could become financially attractive for a larger segment of customers. Further, it has been argued that there is a hedging cost implicit in a flat retail electricity rate, and that by

[100] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 13.
[101] *Ibid.*, p. 130.
[102] *Ibid.*, p. 131.
[103] 2012/2013 Base Residual Auction Report Document, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx.
[104] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 61,400 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), reh'g pending, at P 192.
[105] The payment varies depending on the number of tons of air conditioning a customer has. For more details, see Stephen S. George, Josh Bode and Josh Schellenberg. *Load Impact Estimates for Southern California Edison's Demand Response Program Portfolio*, September 25, 2008.

passing price volatility through to customers in the form of dynamic pricing, electric utilities would avoid this cost and, as a result, should be able to reduce rates by the amount of the risk premium.[106] Accounting for this would further expand the share of customers for whom dynamic rates would be financially attractive. Commonwealth Edison has taken this approach in order to increase consumer interest in its residential RTP program.

Alternatively, some utilities have had success with programs that offer no financial incentive but simply appeal to the customer's desire to help avoid large scale brownouts or blackouts or to improve the environment. A respondent to a recent survey on the barriers to demand response indicated that some of his large commercial customers were happy to respond to phone calls on critical days by reducing load, even without any financial incentives. At the same time, they did not want to formally participate in a demand response program because the paperwork and other requirements were very costly and the savings were not proportionately large.[107] PG&E's air conditioning load control program is another example of how consumers are willing to help out in emergencies for little financial remuneration, and a significant contrast to SCE's program. PG&E has enrolled roughly 75,000 customers in its Smart AC air conditioning cycling program based on a one-time payment of $25 and an appeal indicating that participation would be "doing one small thing" that would "actually help prevent power interruptions and protect the environment."[108]

Technological Barriers

Potential technological barriers to rapid implementation of demand response include the need for new types of metering equipment, metering standards, or communications technology.

Lack of Advanced Metering Infrastructure (AMI)

The lack of AMI poses a very significant barrier to implementing price-based demand response. Currently, there is only one utility in the United States (PPL) that has the metering capability and meter data management systems (MDMS) in place that are necessary to put all of its customers on default dynamic pricing. While there are many millions of meters currently installed that can be read remotely by fixed network, automated meter reading (AMR) systems (which actually transmit data quite frequently), the vast majority of these systems would require significant upgrades to support daily delivery of billing quality, interval data and extensive investment in MDMS and billing systems to support large scale participation in dynamic pricing tariffs. Even in places where a commitment to full interval metering and data management exists, such as California, we are still several years away from being able to place large numbers of customers on default dynamic pricing.

However, progress has been made in terms of developing plans for AMI deployment. In addition to California's decision to equip customers with AMI, the state of Connecticut passed a bill requiring utilities to begin to deploy AMI by 2009. Texas regulators are also moving toward mandatory AMI metering for all customers. Many utilities are planning AMI deployment, or actively analyzing it, including Portland General Electric in Oregon, Central Vermont Public Service in Vermont and Baltimore Gas & Electric, to name just a few. Northeast Utilities is developing a pilot to test the potential impacts of rates that the new smart meters will enable them to provide. Additionally, there are currently ongoing dynamic pricing pilots in Maryland (BGE) and Washington, DC (Pepco). With the requirement in the Energy Policy Act of 2005 (EPAct 2005) that all states investigate time-based metering, cost-effectiveness analyses have been conducted by many other utilities across the US as well.

[106] The lower cost can be estimated by using a well-known formula, which expresses the "risk premium" as an exponential function of retail load volatility, wholesale price volatility and retail load-wholesale price correlation. Monte Carlo simulations under a variety of plausible assumptions yield a median value of 6 percent. See "Rethinking Rate Design," prepared for the Demand Response Research Center, August 2007.

[107] Ahmad Faruqui and Ryan Hledik, "The State of Demand Response in California," prepared for the California Energy Commission, April 2007.

[108] Quote taken from the PG&E direct mail offer letter.

Lack of Cost-Effective Enabling Technologies

There is a diverse menu of technologies that can improve customers' ability to provide demand response, but these technologies are not yet all cost-effective. Examples of enabling technologies include smart thermostats that respond to high prices with an automated adjustment to their setting, whole house gateway systems that allow multiple devices to be similarly made price sensitive, advanced energy management systems in commercial buildings and process control systems in industrial facilities that can reduce load when needed. Customer awareness of these technologies is low and given the low level of market penetration, the cost of the technologies is high, creating a Catch-22 situation.[109] It has also been argued that the marketing infrastructure (the value chain from the equipment manufacturer to the retailer and the installing contractor) is in its infancy. A "market transformation" initiative akin to that pursued in the energy efficiency business may be needed to allow rapid penetration of smart (price sensitive) control technologies in customer premises that would allow them to see the full benefits of demand response.

Concerns about Technological Obsolescence and Cost Recovery

Despite increasing investment in AMI, some regulators and decision makers still have concerns about the useful life of smart meters, as well as the risks that the technology could shortly be replaced with something better.[110] Concerns about technological obsolescence also extend to the previously described enabling technologies, many of which are still in the development phase. Ultimately, these concerns contribute to doubts about the ability to recover the cost of these investments before they need to be replaced. As there is uncertainty surrounding whether state commissions will allow the cost of AMI or enabling technologies to be rate-based, this poses a barrier to increased investment.[111]

Lack of Interoperability and Open Standards

Interoperability and open standards refer to the manner in which various technologies, such as meters and in-home enabling technologies, communicate. If advanced meters contain communication chips based on open communication standards, such as ZigBee, it might be possible for consumers to purchase in-home control and information devices that would automatically communicate with their meter and that, in turn, would help automate or otherwise increase demand response. Open standards might also reduce costs by encouraging competition among technology providers to obtain large scale meter and other technology contracts. A number of jurisdictions and/or utilities are building open communications standards into the functional specifications for AMI systems that they will consider. On the other hand, some have questioned whether the meter should serve as the gateway to Home Area Networks (HAN) and other devices, because this might allow utilities to control the technology and access to meter data by third parties could be limited.

The need for appropriate technical protocols and standards was a key issue at a recent PJM Symposium on Demand Response. The symposium identified a number of topics requiring further development, including region-wide communications protocols, meter data reporting standards, and open access to meter data.[112] More recently, the National Institute of Standards and Technology has contracted with EPRI to develop an interim road map that will serve as a guide to inventory existing standards, and identify the need to resolve differences in standards or create new standards entirely. These standards are scheduled to be submitted to FERC by the end of 2009.

Other Barriers

Some additional barriers do not fall into the categories described above. These barriers are summarized here. These are generally related to customer perceptions of demand response programs and a resulting limited willingness to enroll.

[109] However, the cost of the technologies is rapidly decreasing. The cost of smart thermostats in particular has fallen to less than one-third of the price three years ago.
[110] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.
[111] *Ibid.,* p. 128-129.
[112] Energetics Incorporated, "Proceedings to PJM Symposium on Demand Response," June 8, 2007.

Lack of Customer Awareness and Education

A deficiency of customer education regarding demand response and its benefits has served as a major barrier to further participation in demand response programs. To a large extent, this is evident in a lack of simple customer awareness of demand response programs, which was cited by Toronto Hydro Energy Services as a market transformation barrier for demand response.[113] Inertial behavior also contributes to low participation rates in voluntary programs. Part of this disparity reflects the challenge of creating customer awareness about options, part reflects inertia and still another part reflects uncertainty about the potential benefits of selecting each option. Due to limited customer experience with price-based demand response, and limited utility experience with marketing these programs, a focus on customer education and customer awareness will be key in overcoming this barrier.

Risk Aversion

A significant barrier to customer participation in dynamic pricing options is risk aversion. The Momentum Market Intelligence study cited above also showed that, when selecting a pricing option, customers focus more on the downside risk that their bills might go up if they go on the rate, than on the upside potential that they can save money either by virtue of having a favorable load shape already or by reducing or shifting load from high cost to low cost periods, or both. This risk aversion is one of the primary reasons why default pricing options will lead to much higher customer enrollment than will opt-in enrollment. Research also shows that customers who experience time varying rates have high levels of satisfaction and, when offered the option of staying on such rates, most will do so and will also recommend such tariffs to their friends.[114] Combined, the above research suggests strongly that default, time-based pricing could not only lead to very high participation in such tariffs, but high satisfaction, which is quite contrary to the fears that many express when such notions are suggested.

Fear of Customer Backlash

This has been cited as a concern by some utilities who feel that heavily-used dynamic pricing could cause customer fatigue, cause them to feel exploited if bill savings were small, or trigger a "revolt" in response to the higher critical peak prices. However, others feel that a well designed program, coupled with effective marketing and educational efforts, could prevent this from becoming a significant barrier.[115] The research cited above also strongly suggests that such fears are largely unfounded.

Perceived Lack of Ability to Respond

Some customers feel that they have already done all they can do to become efficient consumers of electricity. This is particularly true in states with highly successful energy efficiency programs. In California, large customers on mandatory TOU rates feel they have already shifted as much of their peak usage to off-peak periods as they can, given the constraints of their business. If these customers were enrolled in a dynamic rate or an additional demand response program, the argument is that they would not know what to do to further reduce peak demand. This is another issue of customer education, where information on cost-effective means for further reducing peak load could facilitate participation in demand response programs for these customers. This barrier is also related to the issue of determining the appropriate financial incentive – given a high enough payment, it could become cost-effective for these customers to curtail consumption for certain end-uses that they otherwise would not do.[116]

Concern Over Environmental Impacts

There is some concern that demand response programs could shift load to off peak hours when coal plants are on the margin, resulting in an increase in emissions. This depends both on the capacity mix in the region and on the impact of demand response on customer consumption patterns. For example, in a

---

[113] Toronto Hydro Energy Services. Development of an Electricity Demand Management and Demand Response Program for Commercial Buildings: Report on Design Charette. November 28, 2003.

[114] See Dean Schultz and David Lineweber, Real Mass Market Customers React to Real Time-Differentiated Rates: What Choices Do They Make and Why? 16th National Energy Services Conference. San Diego, CA. February 2006. See also Momentum Market Intelligence, Statewide Pricing Pilot: End-of-Pilot Participant Assessment. December 2004.

[115] Ahmad Faruqui and Ryan Hledik, "The State of Demand Response in California," prepared for the California Energy Commission, April 2007, p. 28

[116] *Ibid*., p. 27.

region where natural gas plants are almost always the "marginal" units, or for demand response programs that simply reduce consumption during peak periods (without shifting load to off peak periods), negative environmental impacts should not be a concern. However, in a region where, say, a natural gas-fired plant is the marginal unit during peak periods and a coal plant is the marginal unit during off peak periods, if a customer were to respond to a demand response program by shifting load from the peak period to the off-peak period, the net result would be an increase in generation from a plant with higher emissions levels.

Perceived Temporary Nature of Demand Response Impacts

Often, demand response impacts are seen as a deferral of supply side investments rather than as a substitute. In other words, the peak demand reductions from a demand response program could delay necessary investment in, say, a new transmission line, but to the extent that there is still load growth in the region, the transmission line will ultimately need to be built. There may be an expectation that once the transmission line is built, the demand response program will no longer be necessary and will be dropped. This perceived temporary nature of the demand response program could limit willingness of a utility to invest in it, or willingness of customers to participate in it.

APPENDIX D. DATABASE DEVELOPMENT DOCUMENTATION

This appendix provides a detailed summary of the data development process that was used to create the model inputs for the demand response potential assessment. Figure D-1 illustrates how the different data elements were developed. The straight arrows depict relationships between the model inputs, while the dashed arrows show key data sources used in determination of the data elements.

The data elements developed for the assessment and described in this appendix can be broadly classified into two categories:

1. Market characteristics data
    a) Number of customer accounts by rate class by state
    b) Electricity sales by rate class by state
    c) System peak load forecast by state
    d) Average peak load per customer by rate class by state
    e) Growth rate in per customer peak load
    f) Central Air Conditioning (CAC) market saturation data
    g) Advanced Metering Infrastructure (AMI) deployment schedule by state
2. Demand response program related data
    a) Business-As-Usual (BAU) Demand Response Potential estimation
    b) Current participation in demand response programs
    c) Impacts from non-pricing programs
    d) Impacts from pricing programs
    e) Cost-effectiveness analysis

This section describes how each of the data elements listed here was developed.

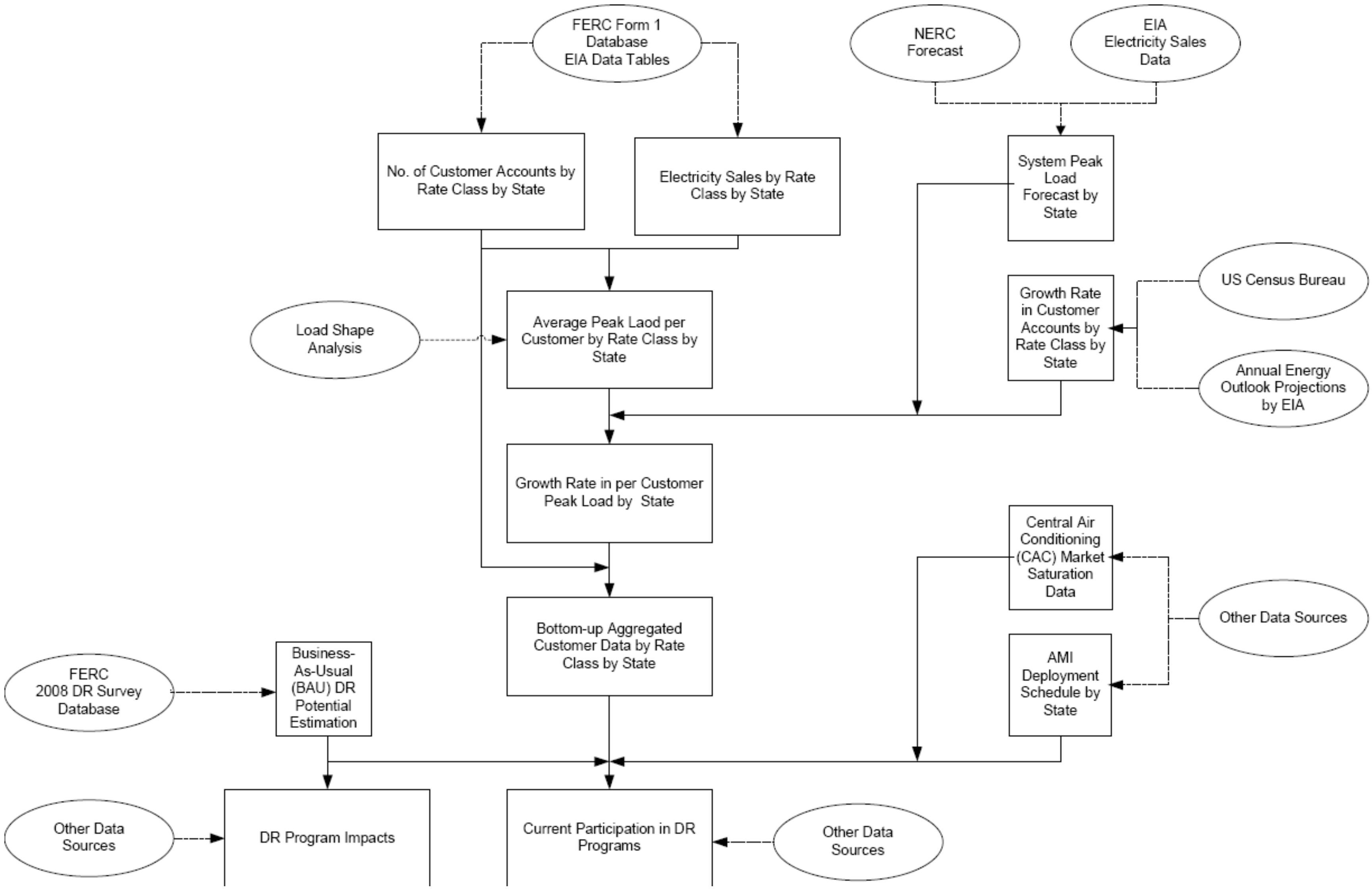


Figure D-1: Data Development for Model Inputs – Relationships Between Data Elements and Key Information Source

Market Characteristics Data

a) Number of Customer Accounts by Rate Class by State

Four rate classes were considered in the model:
1. Residential,
2. Small commercial and industrial (C&I),
3. Medium C&I, and
4. Large C&I.

State-level data, published by EIA[117], provides the number of customers and electricity sales for the residential, commercial, and industrial sectors. Therefore, the number of residential accounts in each state was readily available from the EIA database. However, since the EIA only reports values for the commercial and industrial sectors as a whole, further analysis using FERC Form No. 1[118] data was required in order to determine the breakdown of small, medium, and large C&I accounts for each state. The following steps describe the process undertaken to estimate the number of C&I accounts by rate class for each state.

1. Electricity Sales by Rate Schedule: FERC Form No. 1 data provides the number of accounts and corresponding electricity sales for customers on different rate schedules. FERC Form No. 1 is reported only by IOUs. These data were evaluated and used to calculate electricity sales per customer for each rate schedule.

2. Initial Customer Classification into residential and C&I customers: Customers were then classified into the residential and C&I segments based on the label of the rate schedule provided in FERC Form No. 1. To the extent possible, rate schedule descriptions from utility tariff books were obtained to validate the classifications.

3. Further C&I Customer Classification: The next step was to apply average load factors by rate class to estimate peak load per customer for each rate schedule. The average load factors assumed for the three C&I rate classes were:
   - Load factor for small C&I: 0.6,
   - Load factor for medium C&I: 0.7, and
   - Load factor for large C&I: 0.7.[119]

   These load factors were applied to the electricity sales per customer (Step 1) for each C&I rate schedule in FERC Form No. 1 (Step 2) to estimate peak load per customer. Based on the calculated value of peak load per customer, the C&I rate schedules were grouped into the three C&I rate classes: small, medium, and large. The classification was based on the following ranges for peak load:
   - Small: 0 to 20 kW;
   - Medium: Greater than 20 to 200 kW; and
   - Large: Greater than 200 kW.

   For each utility that reported FERC Form No. 1 data, these first three steps provided an estimation of the percentage of total C&I customers falling into each of the three C&I rate classes.

4. C&I Adjustments for Multi-State Operation by Utilities: Adjustments were then made to C&I data for utilities that had operations in multiple states. For these utilities, the FERC Form No. 1 data on the number of customers and sales were apportioned to all states in which the utilities operate using

[117] http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

[118] FERC Form 1 Database - Electric Utility Annual Report; survey data collected from FERC Form 1 – "Annual Major Electric Utilities, Licensees, and Others." http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp

[119] The load factor assumptions are based on the team's extensive experience working with load shape data and undertaking load shape analysis.

information reported in EIA Form-861. Thus, it was possible to disaggregate the multi-state, utility-reported FERC Form No. 1 data into information for each state in which a given utility operates. This provided a more accurate representation of the number of C&I accounts and sales for each rate class by utility and by state.

5. State-Level Aggregation of Utility Data for C&I Accounts: Multiple utility data for each state were aggregated to arrive at the distribution of small, medium, and large C&I accounts for each state. This assumed that the distribution obtained from FERC Form No. 1 is representative for the state as a whole, with the implicit assumption that the distribution applies to IOUs and non-IOUs as well. Nebraska was the only state for which FERC Form No. 1 data were not available. Since Nebraska's characteristics were assessed to be similar to that of Idaho, Idaho's data were used as a proxy for assuming the C&I distribution for Nebraska.

6. Number of C&I Accounts by Rate Class and State: The final step in estimating the number of C&I accounts by rate class was to apply the percentage distribution for account population by rate class (derived from the previous steps) to the total number of C&I accounts by state (obtained from EIA Form-861 state-level data). This provided the number of C&I accounts by rate class for each state.

Table D-1 lists the resulting number of accounts by state for the residential, small C&I, medium C&I, and large C&I rate classes.

Table D-1: Number of Accounts by Rate Class

State	Number of accounts by rate class			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	2,077,677	362,448	12,354	3,801
Alaska	266,671	45,183	3,270	62
Arizona	2,567,749	280,527	15,965	1,381
Arkansas	1,301,517	199,604	6,629	3,442
California	12,971,924	1,567,550	301,662	17,772
Colorado	2,068,055	282,139	88,021	1,531
Connecticut	1,449,983	141,998	11,261	8,044
Delaware	390,239	47,323	1,475	374
District of Columbia	206,047	24,506	1,842	1,229
Florida	8,615,249	921,368	224,874	9,195
Georgia	4,039,005	483,576	66,628	11,363
Hawaii	409,581	55,808	7,482	632
Idaho	647,581	65,923	55,692	928
Illinois	5,054,895	541,263	26,791	21,435
Indiana	2,734,788	286,888	65,468	8,038
Iowa	1,320,241	183,320	30,471	3,507
Kansas	1,213,189	221,809	10,962	7,594
Kentucky	1,918,247	272,458	27,771	3,050
Louisiana	1,870,160	196,805	89,052	3,192
Maine	693,400	75,666	13,927	1,065
Maryland	2,187,996	230,938	17,496	4,054
Massachusetts	2,631,568	367,459	22,605	4,510
Michigan	4,336,390	485,729	44,172	10,836
Minnesota	2,283,083	189,477	75,091	10,044
Mississippi	1,222,047	228,202	1,565	2,228
Missouri	2,670,172	347,394	25,739	4,651
Montana	456,112	103,892	890	238
Nebraska	787,312	178,123	10,854	2,889
Nevada	1,079,306	145,469	4,497	1,963
New Hampshire	600,399	102,868	831	1,875
New Jersey	3,414,289	461,304	10,998	10,375
New Mexico	829,100	122,560	16,755	1,296
New York	6,855,544	958,009	66,351	5,265
North Carolina	4,128,231	619,832	29,169	3,277
North Dakota	310,222	54,365	2,211	699
Ohio	4,908,791	569,999	59,607	13,010
Oklahoma	1,629,818	243,831	30,398	3,097
Oregon	1,610,829	220,262	36,132	1,521
Pennsylvania	5,217,010	618,439	75,656	10,577
Rhode Island	432,307	48,623	8,614	864
South Carolina	2,028,361	326,244	15,666	2,327
South Dakota	355,714	66,375	658	875
Tennessee	2,660,110	428,663	30,312	3,735
Texas	9,397,317	1,269,490	411,961	5,756
Utah	911,744	103,864	16,754	791
Vermont	310,842	46,230	3,075	313
Virginia	3,170,126	369,208	32,352	7,886
Washington	2,762,275	345,256	26,145	3,568
West Virginia	855,919	135,823	11,181	1,199
Wisconsin	2,581,840	290,192	44,419	4,518
Wyoming	245,648	61,758	3,587	585
Total	**118,473,006**	**15,108,276**	**2,159,118**	**223,764**

b) Electricity Sales by Rate Class by State

The distribution of electricity sales by rate class was determined using the same approach as described above for estimating the number of accounts by rate class. As before, the electricity sales data were readily available for residential accounts from EIA. However, the small, medium, and large C&I sales data had to be developed from FERC Form No. 1 data. FERC Form No. 1 data contains electricity sales data by rate schedule along with number of accounts for IOUs. An analogous estimation methodology to the one already outlined for the number of accounts (see steps 1-6 in the previous section) was used to develop the C&I sales data. The result was state-level aggregate sales data for each of the four rate classes.

Table D-2 lists the resulting electricity sales by state for the residential, small C&I, medium C&I, and large C&I rate classes.

Table D-2: Electricity Sales by Rate Class

State	Electricity Sales by Rate Class (GWh)			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	32,870	26,023	13,385	19,534
Alaska	2,204	1,575	2,030	524
Arizona	33,897	20,352	13,897	7,493
Arkansas	17,788	8,510	3,427	18,824
California	93,402	28,440	73,061	73,567
Colorado	17,752	2,745	20,932	9,767
Connecticut	13,204	2,903	4,336	11,843
Delaware	4,330	3,794	1,118	2,544
District of Columbia	1,853	1,214	1,750	6,509
Florida	119,013	13,879	54,139	45,492
Georgia	55,433	12,525	22,410	46,961
Hawaii	3,309	1,373	2,189	3,944
Idaho	8,438	1,232	9,729	4,051
Illinois	47,145	22,662	4,851	71,030
Indiana	32,818	9,432	20,575	45,653
Iowa	13,723	4,039	8,854	17,897
Kansas	13,886	7,095	2,808	17,045
Kentucky	26,425	14,356	28,538	20,483
Louisiana	29,304	14,262	19,889	17,188
Maine	4,432	915	2,715	4,537
Maryland	27,356	15,727	3,369	17,477
Massachusetts	19,988	12,250	3,494	21,148
Michigan	35,192	15,783	12,829	47,081
Minnesota	22,531	3,252	19,154	23,629
Mississippi	18,612	9,582	693	18,651
Missouri	34,841	8,667	16,457	24,274
Montana	4,602	6,871	858	1,890
Nebraska	9,557	4,182	8,313	5,967
Nevada	12,544	7,982	2,766	12,326
New Hampshire	4,482	2,601	163	4,126
New Jersey	29,594	17,322	5,143	29,307
New Mexico	6,293	3,071	6,164	6,514
New York	50,072	28,910	32,902	30,992
North Carolina	53,736	16,586	27,852	31,033
North Dakota	3,962	2,776	1,737	3,076
Ohio	52,221	25,608	23,471	56,129
Oklahoma	22,610	4,793	12,616	17,143
Oregon	19,731	5,389	16,687	7,474
Pennsylvania	53,550	26,874	19,677	48,843
Rhode Island	3,064	731	1,724	2,475
South Carolina	29,017	11,640	14,959	26,889
South Dakota	4,166	3,290	351	2,524
Tennessee	41,565	22,932	31,213	9,555
Texas	132,220	24,047	115,175	85,287
Utah	8,621	2,587	8,523	7,374
Vermont	2,182	729	1,109	1,921
Virginia	43,624	8,633	16,925	39,493
Washington	35,806	12,788	18,393	20,241
West Virginia	11,199	4,419	5,191	12,151
Wisconsin	22,138	6,646	17,059	25,843
Wyoming	2,585	4,822	1,428	6,490
Total	**1,388,887**	**518,818**	**757,030**	**1,092,209**

c) System Peak Load Forecast by State

System peak demand forecast values are readily available from NERC at the regional level.[120] The NERC peak demand forecast is provided for eight NERC Regions (excluding Alaska and Hawaii) and several sub-regions for four of the NERC regions. Only data for New York are available at the (sub-region) state level. Because the model in the study requires state-level forecast values to serve as a reference point for the demand response impacts, the NERC regional data had to be segmented by state.

The NERC forecast was divided among the states (except for New York, Alaska and Hawaii) according to the percentage of total electric sales for each state[121]. This methodology helps establish consistency between the state system peak forecast and the bottom-up aggregated peak load estimate for a state using customer class data by rate class for number of accounts and average peak load per customer. NERC peak demand data for New York was used directly since it was reported at the state level[122]. Since NERC des not provide values for Alaska and Hawaii, summer peak values for these states were obtained from EIA Form-861 data.

There were limited data sources available for benchmarking the state values. Where available, state values were compared and modified to reflect state filings and planning studies. We also benchmarked national level estimates with data from other sources.[123]

Table D-3 provides the system peak load forecast by state for the time horizon being considered in this study.

[120] 2008 Long Term Reliability Assessment 2008-2017, North American Electric Reliability Corporation, October 2008

[121] Electric Sales, Revenue, and Price, Table 2. Sales to Bundled and Unbundled Consumers by Sector, Census Division, and State, 2006, Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

[122] Comparing the NERC peak demand data for New York with that obtained using the same approach followed for other states reveals that the NERC data is about 10% higher. Nevertheless, it was deemed more accurate to use the NERC data directly in this case.

EIA Form-861 provides utility reported peak values. This EIA data was used to arrive at a national estimation of peak load by aggregating the utility reported peak values in the database. The EIA data was also used to arrive at state peak values by aggregating utility peak data for a state. A comparison of the peak values at the national level showed that the peak value estimated from the EIA data was significantly higher than the total peak load forecast reported by NERC. A comparison of peak estimates at the state level across the two datasets revealed differences. There were some states where peak load estimation using EIA data came close to the NERC forecasted values. But for other states, the peak values from EIA and NERC forecast were different. Differences in state peak estimates can be explained by the nature of utility data reporting in EIA. In the EIA database, utilities with service territories across multiple states, report their peak loads only against one particular state (most likely the state of their mailing address) and do not provide the state-level break-up of their peak. This leads to an inaccurate estimation of the state level peak by simply aggregating the utility reported data.

Table D-3: Peak Demand Forecast by State: [124]

State	Peak demand forecast by state (MW)										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018 (projected)
Alabama	19,000	19,410	19,817	20,191	20,544	20,921	21,344	21,751	22,140	22,536	22,939
Alaska	1,417	1,438	1,459	1,481	1,503	1,526	1,549	1,572	1,596	1,620	1,644
Arizona	18,456	18,862	19,219	19,585	19,964	20,324	20,676	21,030	21,380	21,721	22,067
Arkansas	9,875	10,089	10,296	10,479	10,652	10,836	11,038	11,236	11,426	11,622	11,821
California	57,137	58,395	59,479	60,606	61,814	62,930	64,052	65,183	66,326	67,404	68,500
Colorado	10,837	11,076	11,281	11,495	11,724	11,936	12,149	12,363	12,580	12,785	12,992
Connecticut	7,524	7,658	7,785	7,905	8,016	8,116	8,202	8,277	8,343	8,401	8,459
Delaware	2,503	2,545	2,593	2,630	2,661	2,698	2,734	2,768	2,804	2,836	2,869
District of Columbia	2,403	2,443	2,489	2,524	2,554	2,589	2,625	2,657	2,691	2,723	2,754
Florida	49,453	50,296	51,242	52,470	53,721	54,909	55,952	57,217	58,498	59,788	61,106
Georgia	28,215	28,824	29,428	29,984	30,508	31,068	31,696	32,300	32,878	33,466	34,064
Hawaii	1,790	1,816	1,844	1,871	1,899	1,928	1,957	1,986	2,016	2,046	2,077
Idaho	4,962	5,072	5,166	5,264	5,369	5,465	5,563	5,661	5,760	5,854	5,949
Illinois	30,465	31,019	31,631	32,120	32,552	33,043	33,553	34,033	34,517	34,980	35,449
Indiana	22,890	23,266	23,709	24,043	24,328	24,664	25,000	25,311	25,635	25,933	26,236
Iowa	9,169	9,607	9,945	10,176	10,357	10,527	10,705	10,877	11,045	11,221	11,400
Kansas	8,630	8,820	8,990	9,127	9,256	9,395	9,535	9,678	9,821	9,971	10,124
Kentucky	18,889	19,251	19,637	19,963	20,259	20,588	20,941	21,275	21,605	21,929	22,258
Louisiana	16,332	16,686	17,031	17,341	17,634	17,947	18,293	18,629	18,953	19,283	19,619
Maine	2,812	2,862	2,909	2,954	2,996	3,033	3,065	3,093	3,118	3,140	3,161
Maryland	13,583	13,806	14,069	14,267	14,436	14,636	14,835	15,020	15,212	15,389	15,568
Massachusetts	12,695	12,922	13,134	13,337	13,525	13,693	13,839	13,966	14,077	14,175	14,273
Michigan	23,292	23,820	24,351	24,739	25,063	25,422	25,786	26,127	26,475	26,808	27,144
Minnesota	14,123	14,798	15,318	15,674	15,952	16,214	16,489	16,753	17,013	17,284	17,559
Mississippi	9,835	10,047	10,258	10,451	10,634	10,829	11,048	11,259	11,460	11,665	11,874
Missouri	17,362	17,739	18,102	18,424	18,728	19,053	19,408	19,755	20,090	20,434	20,783
Montana	2,991	3,075	3,143	3,206	3,268	3,326	3,385	3,443	3,502	3,559	3,616
Nebraska	5,771	6,047	6,260	6,405	6,519	6,626	6,738	6,846	6,952	7,063	7,175
Nevada	7,538	7,704	7,847	7,996	8,155	8,303	8,451	8,600	8,751	8,893	9,038
New Hampshire	2,539	2,585	2,627	2,668	2,705	2,739	2,768	2,794	2,816	2,835	2,855
New Jersey	17,273	17,559	17,889	18,143	18,361	18,613	18,862	19,092	19,329	19,547	19,768
New Mexico	4,671	4,774	4,863	4,953	5,050	5,139	5,230	5,321	5,413	5,500	5,589
New York	33,809	34,167	34,444	34,768	35,112	35,475	35,807	36,133	36,436	36,762	37,091
North Carolina	26,548	27,120	27,689	28,212	28,706	29,232	29,823	30,392	30,936	31,489	32,051
North Dakota	2,379	2,493	2,581	2,641	2,687	2,732	2,778	2,822	2,866	2,912	2,958
Ohio	33,238	33,799	34,443	34,931	35,351	35,843	36,335	36,794	37,270	37,715	38,165
Oklahoma	11,919	12,183	12,418	12,606	12,784	12,976	13,170	13,367	13,565	13,772	13,983
Oregon	10,476	10,706	10,905	11,112	11,333	11,538	11,744	11,951	12,160	12,358	12,559
Pennsylvania	31,488	32,007	32,616	33,075	33,467	33,930	34,392	34,820	35,265	35,676	36,092
Rhode Island	1,785	1,817	1,847	1,875	1,902	1,926	1,946	1,964	1,979	1,993	2,007
South Carolina	16,947	17,312	17,675	18,009	18,324	18,660	19,037	19,400	19,747	20,100	20,460
South Dakota	2,128	2,229	2,308	2,361	2,403	2,443	2,484	2,524	2,563	2,604	2,645
Tennessee	22,475	22,960	23,441	23,884	24,302	24,747	25,248	25,729	26,190	26,658	27,134
Texas	72,723	74,203	75,734	77,169	78,381	79,898	81,259	82,637	83,881	85,433	87,014
Utah	5,742	5,868	5,977	6,090	6,212	6,324	6,437	6,550	6,665	6,773	6,884
Vermont	1,085	1,099	1,112	1,125	1,139	1,152	1,165	1,178	1,192	1,205	1,218
Virginia	22,412	22,882	23,357	23,785	24,186	24,617	25,097	25,557	26,000	26,447	26,902
Washington	18,538	18,946	19,298	19,663	20,055	20,417	20,782	21,149	21,519	21,869	22,225
West Virginia	6,916	7,042	7,181	7,295	7,396	7,510	7,630	7,744	7,857	7,967	8,078
Wisconsin	14,845	15,458	15,951	16,292	16,562	16,825	17,099	17,362	17,622	17,887	18,157
Wyoming	3,236	3,326	3,401	3,469	3,536	3,599	3,662	3,725	3,789	3,850	3,912
Total	**793,121**	**809,926**	**826,192**	**840,838**	**854,547**	**868,879**	**883,359**	**897,672**	**911,725**	**925,880**	**940,267**

[124] The peak load numbers are based on the NERC report titled '2008 Long Term Reliability Assessment 2008-2017', October 2008. The NERC report provides the peak demand forecast for eight NERC regions (excluding Alaska and Hawaii). Peak demand values for Alaska and Hawaii were obtained from EIA Form-861 data and added to the NERC total to arrive at the total peak demand estimates for the whole U.S.

d) Average Peak Load per Customer by Rate Class by State

One of the key inputs to demand response potential estimation is average electricity use per customer per hour during time periods when demand response programs are likely to be used but before any demand response occurs. We refer to the time period representing when demand response has a high probability of being used as the "peak period" on a "typical event day" and represent that period by the hours between 2 and 6 pm on the top 15 system load days in each state. Note that average energy use across the top 15 system load days will produce demand response load impact estimates that are significantly lower than if they were based on the single hour of system peak or based on fewer than the top 15 system load days. Utility and/or ISO system load data were used to identify top system load days in each state.

Hourly load data are not available for all utilities and states or for all customer segments within states. Indeed, no data at all were found that distinguished between residential customers with and without central air conditioning. Fortunately, hourly load data were available on a large enough cross section of utilities that it was possible to use regression analysis to estimate normalized load shapes for each relevant customer segment and to use these models to develop load shapes for all other states and customer segments. Table D-4 summarizes utilities from which hourly load data was used by state and customer segment. Following Table D-4 is a list of the data sources for each utility.

Table D-4: Summary of Utility Data Used in Regression Analysis

Summary of Utility Data Used in Regression Analysis				
State	**Residential**	**Small C&I**	**Medium C&I**	**Large C&I**
California	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E
Connecticut	United Illuminating Company	United Illuminating Company	United Illuminating Company	United Illuminating Company
District of Columbia	Pepco	Pepco	Pepco	Pepco
Idaho	Idaho Power	Idaho Power	Idaho Power	Idaho Power
Illinois	Amaren, ComEd	Amaren	Amaren	Amaren
Indiana	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Massachusetts	National Grid	National Grid	National Grid	National Grid
Maryland	Pepco, BG&E	Pepco, BG&E	Pepco	Pepco
Maine	Central Maine Power	Central Maine Power	Central Maine Power	Central Maine Power
Michigan	Detroit Edison	Detroit Edison	Detroit Edison	Detroit Edison
Missouri	Amaren	Amaren	Amaren	Amaren
North Carolina	Duke Energy	Duke Energy	Duke Energy	Duke Energy
New Hampshire	National Grid	National Grid	National Grid	National Grid
New Jersey	JCPL, PSEG	JCPL	JCPL	JCPL, PSEG
New York	National Grid	National Grid	National Grid	National Grid
Ohio	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Pennsylvania	MetEd, Penelec	MetEd, Penelec	MetEd, Penelec	MetEd, Penelec
Rhode Island	National Grid	National Grid	National Grid	National Grid
South Carolina	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Texas	Ercot	Ercot	Ercot	Ercot
Vermont	Burlington Electric	Burlington Electric	Burlington Electric	Burlington Electric

Utilities List with Sources

- **PG&E**: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml
- **SCE**: http://www.sce.com/AboutSCE/Regulatory/loadprofiles/loadprofiles.htm
- **SDGE**: FSC Internal
- **United Illuminating Company**: http://www.uinet.com/uinet/connect/UINet/Top+Navigator/About+UI/Doing+Business+With+UI/Suppliers+-+Aggregators/Load+Profiles/
- **Pepco**: https://suppliersupport.pepco.com/suppliersupport/suppliersupportframe.htm
- **Idaho Power**: GEP Internal
- **Ameren**: http://www.ameren.com/IlChoice/adc_cc_profile_select.asp
- **ComEd**: FSC Internal
- **Duke Energy**: FSC Internal
- **National Grid MA**: https://www.nationalgridus.com/masselectric/energy_supplier/index.asp
- **National Grid RI**: https://www.nationalgridus.com/narragansett/energy_supplier/index.asp
- **National Grid NH**: https://www.nationalgridus.com/granitestate/energy_supplier/index.asp
- **National Grid NY**: http://www.nationalgridus.com/niagaramohawk/energy_supplier/elec_load_profile.asp
- **BG&E**: http://supplier.bge.com/LoadProfiles_EnergySettlement/historicalloaddata.htm
- **Central Maine Power**: FSC Internal
- **Detroit Edison**: http://www.suppliers.detroitedison.com/internet/infocenter/custdata/loadprofiles/profiles.jsp
- **JCPL**: http://www.firstenergycorp.com/supplierservices/New_Jersey/Load_Profiles.html
- **PSEG**: http://www.pseg.com/customer/energy/energy_profiles.jsp
- **Penelec**: http://www.firstenergycorp.com/supplierservices/Pennsylvania/Met-Ed_and_Penelec/ME_and_PN_Load_Profile.html
- **MetEd**: http://www.firstenergycorp.com/supplierservices/Pennsylvania/Met-Ed_and_Penelec/ME_and_PN_Load_Profile.html
- **Ercot**: http://www.ercot.com/mktinfo/loadprofile/
- **Burlington Electric**: FSC Internal

Data from the utilities identified in Table D-4 were used to estimate regression models that relate normalized hourly load to a variety of variables that influence load in each hour, including weather, central air conditioning saturation and seasonal, monthly, day-of-week and hourly usage patterns. This statistical analysis was used to separate weather sensitive and non-weather sensitive load for residential customers. The normalized load shapes were then combined with estimates of average annual energy use and central air conditioning saturation by customer segment for each state and state-specific weather data to produce hourly load estimates for each customer segment and state. The average, hourly energy use between 2 and 6 pm on the top 15 system load days was used as the basis for estimating load impacts for price-based demand response options for each customer segment. The outcome of this estimation process is summarized in Table D-5.

Table D-5: Average Energy Use per Hour (2 - 6 pm) on Top 15 System Peak Days

Average Energy Use per Hour Between 2 and 6 pm on Top 15 System Peak Days (kWh/hr)					
State	Residential No CAC	Residential with CAC	Small C&I (<20kW)	Medium C&I (20-200kW)	Large C&I (>200kW)
Alabama	1.88	4.29	15.06	192.09	747.82
Alaska	0.89	0.94	4.48	79.82	1029.24
Arizona	1.56	4.18	16.88	165.50	822.41
Arkansas	1.62	3.80	9.09	92.64	800.59
California	0.83	1.79	3.18	37.63	555.49
Colorado	1.01	2.11	1.91	40.05	901.10
Connecticut	1.01	3.35	3.89	63.37	205.70
Delaware	1.27	2.53	15.17	125.09	951.18
District of Columbia	1.03	2.10	9.52	158.33	744.54
Florida	1.64	3.21	2.90	40.13	695.77
Georgia	1.63	3.73	5.44	59.68	601.70
Hawaii	0.89	1.49	4.20	45.07	841.74
Idaho	1.54	3.56	3.95	30.98	636.35
Illinois	1.07	1.84	7.31	28.29	449.82
Indiana	1.38	2.78	6.32	52.36	798.43
Iowa	1.19	2.27	4.11	47.31	709.25
Kansas	1.38	3.07	6.38	43.67	317.52
Kentucky	1.64	3.45	10.51	176.00	958.65
Louisiana	1.86	3.99	14.62	38.52	771.32
Maine	0.71	1.71	2.04	29.65	570.85
Maryland	1.43	2.92	13.09	32.10	606.14
Massachusetts	0.84	2.42	5.98	24.48	641.85
Michigan	0.93	1.85	6.18	48.07	608.74
Minnesota	1.13	2.17	3.21	41.64	327.42
Mississippi	1.81	4.10	8.76	78.15	1214.63
Missouri	1.55	3.33	5.03	110.37	748.32
Montana	1.19	2.27	12.28	156.79	1100.58
Nebraska	1.40	2.82	4.55	127.93	291.10
Nevada	1.38	3.39	12.07	112.40	930.63
New Hampshire	0.83	2.65	4.73	32.07	305.90
New Jersey	0.95	3.24	7.11	77.16	394.96
New Mexico	0.90	1.78	4.81	61.23	707.20
New York	0.80	2.65	5.67	81.14	819.98
North Carolina	1.55	3.48	5.57	168.27	1373.15
North Dakota	1.47	2.85	9.65	129.07	614.41
Ohio	1.22	2.43	8.53	65.09	603.86
Oklahoma	1.67	3.61	3.84	69.80	777.67
Oregon	1.45	2.68	4.52	74.62	679.85
Pennsylvania	1.18	2.32	8.18	42.74	644.24
Rhode Island	0.78	2.29	2.72	31.84	392.99
South Carolina	1.70	4.01	7.64	171.79	1696.41
South Dakota	1.35	2.57	9.28	87.11	401.63
Tennessee	1.86	4.41	11.51	185.85	376.15
Texas	1.69	3.71	3.73	47.23	2086.24
Utah	1.11	2.34	4.91	86.14	1322.23
Vermont	0.78	2.12	2.19	48.54	772.87
Virginia	1.58	3.32	4.58	88.22	708.11
Washington	1.53	2.60	6.50	109.94	771.14
West Virginia	1.50	3.13	6.34	78.07	1431.48
Wisconsin	0.99	1.72	4.08	60.61	781.90
Wyoming	1.24	2.46	14.86	65.71	1550.80

The statistical models underlying the estimates in Table D-5 were estimated using panel regressions. Each load profile represented an individual panel (broken down by utility, region, state and customer class). Each panel contained data in hourly form, for at least one consecutive year's worth of data (8,760 hourly observations), with some panels containing several years of data. The regression models were designed to accurately predict normalized hourly load for electricity customers nationwide given the time of day, day of week, and month, with a focus primarily on the accuracy of the predictions in the months and hours of the day when a demand response event is likely to be called. Hourly loads were estimated for the four customer classes: Residential and Small, Medium and Large commercial and industrial. Separate models were estimated for residential customers in the New England states and non-New England states. This segmentation was intended to reflect inherent differences in the housing stock. Homes in the New England states are typically older, smaller and have a much lower CAC penetration due to a lack of centralized vents. This also typically results in a much higher concentration of room air conditioners, a variable for which there is no reliable data source. With the effect of the temperature-based variables in the model scaled directly by CAC penetration, segmenting the residential class ensures appropriate coefficients for these variables. Without the segmentation, the model produced biased estimates at the low end of the saturation of central air conditioning due to the bias in the New England states.

For each customer segment, functional form was closely considered and then several specifications were tested using a fixed-effects panel regression model. This approach controls for auto-correlation in the errors and ensures correct standard errors. The selection of the final regression model was based on its accuracy under normal and extreme weather conditions, and on its theoretical consistency. The same specification was used for all customer segments, with the main difference being that CAC penetration varies in the residential segment, while it is held constant for the C&I segments. With C&I load much less dependent on CAC load, and variation in CAC penetration significantly lower in these segments, this is a valid approach.

The final models depict normalized energy use for customers across states and classes as a function of variables that capture typical load shapes associated with operational schedules, and, for the residential model, variables designed to capture central air conditioning load based on central air conditioning penetration and cooling-degree-hours. The dependent variable in each regression consisted of normalized hourly energy use, and the explanatory variables for the residential model were:

- Hourly binary variables to define the typical load profile for a day;
- Monthly binary variables to capture seasonal variation;
- Day-of-week binary variables to capture variation in energy use throughout the week;
- A weekend & holiday binary variable interacted with hourly binary variables to capture the different hourly load profile typically found on weekends or holidays;
- A Monday or Friday binary variable interacted with hourly binary variables to capture the different hourly load profiles found on Mondays and Fridays;
- Cooling-Degree-Hours * Central Air Conditioning Penetration interacted with hour binary variables to capture the impact of air conditioning load across the hours;

Mathematically, the regressions can be expressed by:

$$normalizedkW_{xt} = a_x + \sum_{i=5}^{9} b_i \cdot Month_i + \sum_{k=1}^{7} c_k \cdot Dayofweek_k + \sum_{j=1}^{24} d_j \cdot Hour_j + \sum_{j=1}^{24} e_j \cdot Hour_j \cdot Weekendholiday + \sum_{j=1}^{24} f_j \cdot Hour_j \cdot MondayOrFriday + \sum_{j=1}^{24} g_j \cdot Hour_j \cdot CoolingDegreeHours \cdot CACpenetration + U_{xt}$$

In this equation,

$normalizedkW_{xt}$ represents the normalized hourly usage for state or utility x at time t;

a - g are estimated parameters;

$Month_i$ is a dummy variable for month i;

$Dayofweek_k$ is a dummy variable for day of week k;

$Hour_j$ is a dummy variable for hour j;

Weekendholiday is a dummy variable specifying the day as either a weekend or holiday;

MondayOrFriday is a dummy variable specifying the day as either a Monday or Friday;

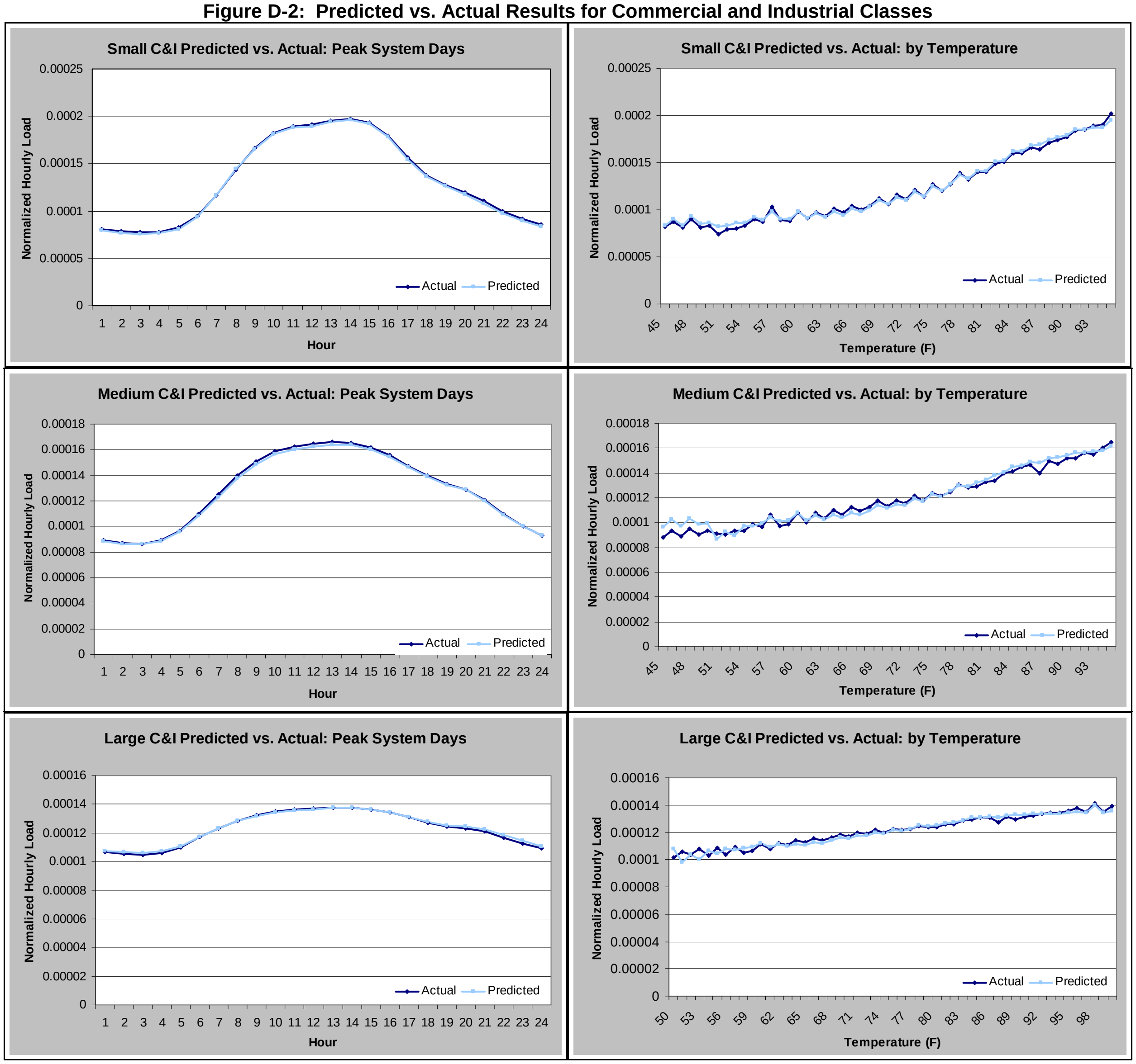
CoolingDegreeHours is the cooling degree hours measured as the maximum of 0 or temperature - 65

U_{xt} is the error term;

The accuracy of the models' predictions across all the states hinges on the amount of variation in the load profiles used as inputs. As indicated in Table D-4, load data underlying the regressions span a wide range of geographic regions and include hot and cold climates, humid and dry climates, and a wide variation in central air conditioning saturation.

An analysis of the Predicted vs. Actual loads shows that the models predict well for all customer classes across various metrics. Figure D-2 shows the predicted vs. actual results for the commercial and industrial classes. Model accuracy is excellent even at the high end of the temperature spectrum and across all hours of the day during peak (top 15) system load days.

Figure D-2: Predicted vs. Actual Results for Commercial and Industrial Classes



Figures D-3 and D-4 compare predicted and actual values for the residential model. As with the C&I models, the residential models predict well across the temperature spectrum. When comparisons are made for states grouped according to CAC saturation, it is evident that even with the segmented models, the predicted values are low at high temperature values for states with lower CAC saturations. Indeed, the average under-prediction across all states for the peak period on the top 15 system load days is 8.5 percent. While not ideal, this under prediction means that the price-based, demand response potential estimates are conservative. Furthermore, predictions are very accurate for the higher CAC quadrants, even at high temperatures, which is where the majority of residential demand response potential will come from.

Figure D-3: Residential Actual vs. Predicted by Temperature

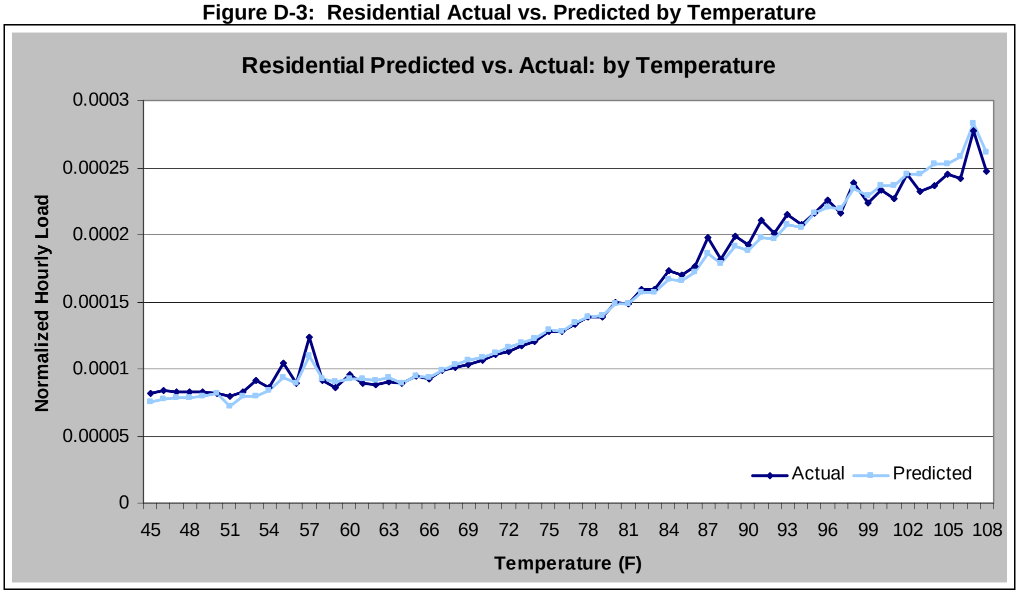


Figure D-4: Residential Actual vs. Predicted by Temperature; CAC Quadrant

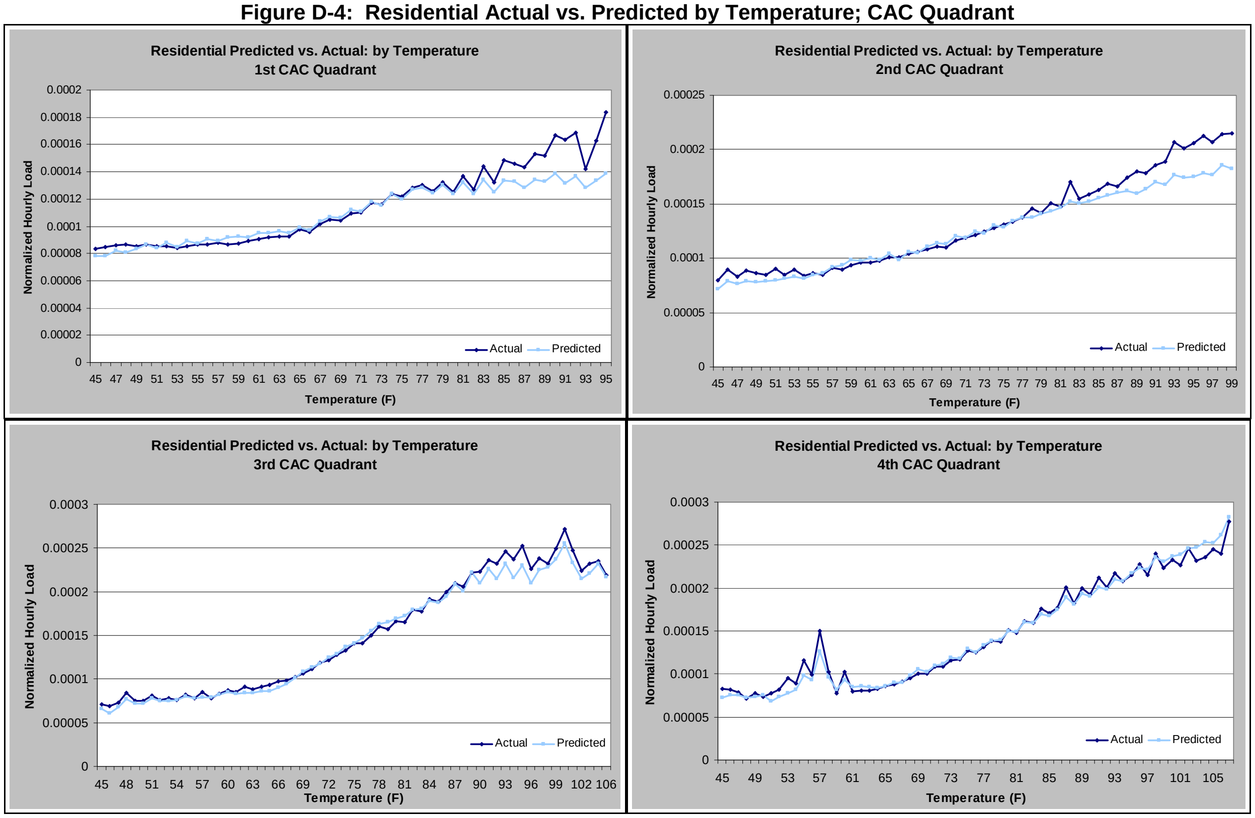


Table D-6 provides the average per-customer peak load by state.

Table D-6: Average Per-Customer Peak Load by Rate Class

State	Average peak load per customer (kW)			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	3.4	15.1	192	748
Alaska	0.9	4.5	80	1,029
Arizona	3.8	16.9	165	822
Arkansas	2.8	9.1	93	801
California	1.2	3.2	38	555
Colorado	1.5	1.9	40	901
Connecticut	1.6	3.9	63	206
Delaware	1.9	15.2	125	951
District of Columbia	1.6	9.5	158	745
Florida	3.1	2.9	40	696
Georgia	3.4	5.4	60	602
Hawaii	1.0	4.2	45	842
Idaho	2.9	3.9	31	636
Illinois	1.7	7.3	28	450
Indiana	2.4	6.3	52	798
Iowa	1.9	4.1	47	709
Kansas	2.8	6.4	44	318
Kentucky	3.0	10.5	176	959
Louisiana	3.5	14.6	39	771
Maine	0.8	2.0	30	571
Maryland	2.6	13.1	32	606
Massachusetts	1.0	6.0	24	642
Michigan	1.5	6.2	48	609
Minnesota	1.7	3.2	42	327
Mississippi	3.5	8.8	78	1,215
Missouri	3.1	5.0	110	748
Montana	1.6	12.3	157	1,101
Nebraska	2.6	4.5	128	291
Nevada	3.1	12.1	112	931
New Hampshire	1.1	4.7	32	306
New Jersey	2.2	7.1	77	395
New Mexico	1.3	4.8	61	707
New York	1.3	5.7	81	820
North Carolina	3.2	5.6	168	1,373
North Dakota	2.2	9.7	129	614
Ohio	2.0	8.5	65	604
Oklahoma	3.3	3.8	70	778
Oregon	1.9	4.5	75	680
Pennsylvania	1.7	8.2	43	644
Rhode Island	1.0	2.7	32	393
South Carolina	3.6	7.6	172	1,696
South Dakota	2.2	9.3	87	402
Tennessee	3.9	11.5	186	376
Texas	3.3	3.7	47	2,086
Utah	1.6	4.9	86	1,322
Vermont	0.9	2.2	49	773
Virginia	2.5	4.6	88	708
Washington	1.8	6.5	110	771
West Virginia	2.3	6.3	78	1,431
Wisconsin	1.4	4.1	61	782
Wyoming	1.7	14.9	66	1,551

e) Growth Rate in per Customer Peak Load

In estimating the growth rate in peak load per customer, the analysis started with base year values for the following items:

1. Growth rate in number of accounts by rate class,
2. Average peak load per customer account by rate class, and
3. State peak forecast.

In order to estimate the growth rate in critical peak per customer, it is first necessary to estimate the growth rate in account population by rate class. For the residential sector, the population forecast for each state was readily obtained from the U.S. Census Bureau and this was assumed to apply directly to the growth rate of residential accounts. In order to estimate the growth rate in accounts for all C&I rate classes, growth rates in 'Commercial sq.ft.' were used as a proxy (obtained from Supplemental Tables to the Annual Energy Outlook 2008 that provides projections on Commercial Sq.ft. by census division)[125], since better estimates were not available.

The overall peak load for a particular rate class is arrived at by aggregating the product of critical peak load per account and the number of accounts by rate class. It is assumed that the overall peak load for each rate class grows at the same rate as the system peak, obtained from NERC forecast values (as explained in the previous section). Therefore, in the final step, the underlying assumptions related to growth rate in number of accounts by rate class on the growth in aggregate peak load by rate class were used to ascertain the implicit critical peak growth rates per customer by rate class.

Table D-7 lists the population and critical peak growth rate values for each state.

[125] 'Supplemental Tables to the Annual Energy Outlook 2008" – http://www.eia.doe.gov/oiaf/archive/aeo08/supplement/index.html

Table D-7: Growth Rate in Population and Critical Peak Load by Rate Class

State	Population growth rate (%)				Critical peak growth rate (%)	
	Residential	Small C&I	Medium C&I	Large C&I	Residential	All C&I
Alabama	0.3	1.3	1.3	1.3	1.6	0.6
Alaska	1.1	1.3	1.3	1.3	0.4	0.2
Arizona	1.6	1.7	1.7	1.7	0.2	0.1
Arkansas	0.6	1.5	1.5	1.5	1.2	0.3
California	1.1	1.5	1.5	1.5	0.8	0.4
Colorado	0.9	1.7	1.7	1.7	0.9	0.1
Connecticut	0.3	0.8	0.8	0.8	0.9	0.4
Delaware	0.9	1.3	1.3	1.3	0.4	0.1
District of Columbia	-0.1	1.3	1.3	1.3	1.5	0.1
Florida	2.0	1.6	1.6	1.6	0.2	0.6
Georgia	1.3	1.6	1.6	1.6	0.6	0.3
Hawaii	0.6	1.3	1.3	1.3	0.9	0.2
Idaho	1.4	1.7	1.7	1.7	0.4	0.1
Illinois	0.3	1.1	1.1	1.1	1.3	0.4
Indiana	0.4	1.1	1.1	1.1	1.0	0.3
Iowa	0.6	1.1	1.1	1.1	1.6	1.1
Kansas	0.3	1.1	1.1	1.1	1.3	0.5
Kentucky	0.4	1.3	1.3	1.3	1.3	0.4
Louisiana	0.3	1.5	1.5	1.5	1.6	0.4
Maine	0.4	0.8	0.8	0.8	0.7	0.4
Maryland	1.0	1.3	1.3	1.3	0.4	0.1
Massachusetts	0.3	0.8	0.8	0.8	0.8	0.4
Michigan	0.3	1.1	1.1	1.1	1.2	0.4
Minnesota	0.9	1.1	1.1	1.1	1.3	1.1
Mississippi	0.3	1.3	1.3	1.3	1.6	0.6
Missouri	0.5	1.1	1.1	1.1	1.3	0.7
Montana	0.6	1.7	1.7	1.7	1.3	0.2
Nebraska	0.6	1.1	1.1	1.1	1.6	1.1
Nevada	1.6	1.7	1.7	1.7	0.2	0.1
New Hampshire	1.0	0.8	0.8	0.8	0.2	0.4
New Jersey	0.5	0.7	0.7	0.7	0.8	0.7
New Mexico	0.6	1.7	1.7	1.7	1.2	0.1
New York	0.1	0.7	0.7	0.7	0.8	0.3
North Carolina	1.4	1.6	1.6	1.6	0.5	0.3
North Dakota	0.6	1.1	1.1	1.1	1.6	1.1
Ohio	0.1	1.1	1.1	1.1	1.3	0.3
Oklahoma	0.4	1.5	1.5	1.5	1.2	0.1
Oregon	1.1	1.5	1.5	1.5	0.7	0.4
Pennsylvania	0.2	0.7	0.7	0.7	1.2	0.7
Rhode Island	0.4	0.8	0.8	0.8	0.8	0.4
South Carolina	0.9	1.6	1.6	1.6	1.0	0.3
South Dakota	0.6	1.1	1.1	1.1	1.6	1.1
Tennessee	0.9	1.3	1.3	1.3	1.0	0.6
Texas	1.5	1.5	1.5	1.5	0.3	0.3
Utah	1.4	1.7	1.7	1.7	0.4	0.1
Vermont	0.6	0.8	0.8	0.8	0.6	0.4
Virginia	1.1	1.6	1.6	1.6	0.7	0.3
Washington	1.2	1.5	1.5	1.5	0.6	0.4
West Virginia	-0.1	1.5	1.5	1.5	1.6	0.1
Wisconsin	0.5	1.1	1.1	1.1	1.5	0.9
Wyoming	0.3	1.7	1.7	1.7	1.6	0.2

f) Central Air Conditioning (CAC) Market Saturation Data

As a first step in determining the saturation of CAC equipment in the residential sector, CAC saturation values were compiled from a combination of primary and secondary information sources for each state. These multiple sources included EIA Regional Energy Consumption Survey (RECS) data, American Housing Survey data, utility reports, specific reports on state-level appliance saturation surveys, and information obtained from utilities through direct contacts (indicated in Table D-8).

For states with data from multiple sources, professional judgment was used to determine the data that provided the closest approximation to the state level value in order to estimate the default saturation value for each state. The estimation approach varied by state; sometimes a single best source value was used as the default estimate, while at other times CAC saturation values were obtained from multiple sources. The specific methodology used for estimating the default value for each state is indicated in Table D-8.

For the C&I sector, CAC saturation values were obtained from the Commercial Building Energy Consumption Survey (CBECS) data provided by EIA.[126]

Table D-8 summarizes the residential CAC saturation values and how they were derived.

[126] Please refer to Table B41, 'Cooling Equipment Floorspace for Non-Mall Buildings". http://www.eia.doe.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/2003set8/2003excel/b41.xls, published by EIA. The table provides cooling saturation by building floorspace for the four census regions. We assume that small C&I buildings have floor space less than 25,000 sq.ft., For medium C&I customers, we assume that the floor space area ranges between 25,000 to 250,000 sq.ft. This data is available only at the Census region level. All states falling within a census region are assumed to have the same saturation value.

Table D-8: Residential CAC Saturation Values by State

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Alabama	62.0%	Used higher value based on CDD compared to other states in census division.	55.1%	2005 RECS data from EIA for East South Central Division, Table HC13.6.
			62.0%	Southern Company Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Alaska	2.5%	One data source	0.0%	Information from Todd Hoener at Golden Valley Electric Assn.
		Average of two sources	5%	BC Hydro 2003 Residential End Use Study (Northern Region)
Arizona	86.8%	Used value obtained from APS -more current than AHS data	86.8%	Information from Jim Wantor at Arizona Public Service (APS). Based on a saturation study: 75% of residential customers are in the desert and 99% of them have CAC, while 25% of customers are not in the desert and half of them have CAC.
			92.1%	American Housing Survey (AHS) for the Phoenix Metropolitan Area: 2002, U.S. Census Bureau.
Arkansas	54.6%	One data source	54.6%	Association of Electric Cooperatives of Arkansas (AECC): Appliance Saturation Survey indicates that in 2006 approximately 54.6% of the electric cooperatives' residential consumers in Arkansas had electric central air conditioning.
California	41.0%	RASS data was used as the default data source	41.0%	California Statewide Residential Appliance Saturation Study (RASS), June 2004.
			79.9%	American Housing Survey (AHS) for the Sacramento, CA Metropolitan Area: 2004, U.S. Census Bureau.
			47.4%	American Housing Survey (AHS) for the Santa Ana, CA Metropolitan Area: 2002, U.S. Census Bureau.
			38.7%	American Housing Survey (AHS) for the Los Angeles, CA Metropolitan Area: 2003, U.S. Census Bureau.
			70.5%	American Housing Survey (AHS) for the San Bernardino-Ontario, CA Metropolitan Area: 2002, U.S. Census Bureau.
			34.5%	American Housing Survey (AHS) for the San Diego, CA Metropolitan Area: 2002, U.S. Census Bureau.
			45.0%	2005 RECS data from EIA.
Colorado	47.2%	Average of PSC and AHS values. Tri-state data seems low compared to other values.	45.0%	Information from Bruce Nielson at the Public Service Co (PSC) of Colorado. Information provided is for 2006.
			49.5%	American Housing Survey (AHS) for the Denver Metropolitan Area: 2004, U.S. Census Bureau.
			22.6%	Tri-State: Jim Spiers provided data for Tri-State's 4 states from a "recent residential end-use survey of our 44 Members in Colorado, Wyoming, Nebraska and New Mexico."
Connecticut	26.9%	One data source	26.9%	American Housing Survey (AHS) for the Hartford Metropolitan Area: 2004, U.S. Census Bureau.
Delaware	53.0%	One data source	53.0%	PHI AMI business case filing
District of Columbia	56.0%	One data source	56.0%	PHI AMI business case filing
Florida	91.0%	RECS data	93.0%	Information from John Haney at FPL.
			84.9%	American Housing Survey (AHS) for the Miami/Ft Lauderdale Metropolitan Area: 2002, U.S. Census Bureau.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
			91.0%	2005 RECS data from EIA.
			68.0%	Southern Company Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Georgia	82.2%	Average of all data - SoCo is current, but low compared to AHS value.	91.5%	American Housing Survey (AHS) for the Atlanta Metropolitan Area: 2004, U.S. Census Bureau.
			73.0%	Southern Company (SoCo) Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Hawaii	17.6%	Weighted average based on number of households for each utility	22.5%	Hawaiian Electric Co.: 2007 REEPs.
			4.1%	Maui Electric Co.: Residential Appliance Survey, 7/03.
			1.2%	Hawaii Electric Light Co.: 2007 Residential Appliance Saturation Survey.
Idaho	66.5%	One data source	66.5%	Information from P. Werner at Idaho Power Co. According to him, in the last residential end-use survey of Idaho Power's service territory (not the state) in 2004, the central AC saturation including heat pumps was 60.6%. The current saturation is an estimate.
Illinois	75.0%	Average of AHS and Xcel Energy value - including MEEA data raises average to 81% which seems out of line compared to other states in census division.	60.0%	American Housing Survey (AHS) for the Chicago Metropolitan Area: 2003, U.S. Census Bureau.
			90.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			94.3%	Claire Saddler, ComEd, wrote that MEEA conducted 309 SF home survey in 2003. This research found that 94.3% of those sampled had central A/C.
Indiana	74.4%	Average of all data - factors in the more current Xcel Energy value and the AHS data for the Indianapolis area.	82.8%	American Housing Survey (AHS) for the Indianapolis Metropolitan Area: 2004, U.S. Census Bureau.
			66.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Iowa	70.0%	One data source	70.0%	IPL Energy Efficiency Plan Vol. II Appendix D (Iowa Utility Assoc. State-Wide Savings Potential Study 8/2/07).
Kansas	83.7%	One data source	83.7%	American Housing Survey (AHS) for the Kansas City Metropolitan Area: 2002, U.S. Census Bureau.
Kentucky	76.0%	One data source	76.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Louisiana	75.5%	One data source	75.5%	American Housing Survey (AHS) for the New Orleans Metropolitan Area: 2004, U.S. Census Bureau.
Maine	14.0%	One data source	14.0%	Data obtained from FSC.
Maryland	78.0%	One data source	78.0%	BGE AMI business case filing
Massachusetts	12.7%	One data source	12.7%	2005 RECS data (New England Division); Table HC11.6.
Michigan	57.2%	Average of all data - values are fairly close	56.0%	Electric Demand Comparison, Consumers Energy 6/22/06 (2008 value).
			60.9%	American Housing Survey (AHS) for the Detroit Metropolitan Area: 2003, U.S. Census Bureau.
			52.0%	Consumers Energy Demand Response program plan
			60.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Minnesota	51.2%	Average of all data - values are fairly close	48.3%	Great River Energy Planning Study, 2003.
			54.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Mississippi	74.7%	Average of all data - SoCo data is more current, but low compared to AHS data.	81.4%	American Housing Survey (AHS) for the Memphis Metropolitan Area: 2004 (also including parts of AR, MS), U.S. Census Bureau.
			68.0%	Southern Company (SoCo) Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Missouri	87.5%	Average of all data - values are fairly close	92.0%	2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study, 2006.
			85.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			85.5%	American Housing Survey (AHS) for the St. Louis Metropolitan Area: 2004 (also including part of IL), U.S. Census Bureau.
Montana	42.1%	One data source	42.1%	2005 RECS data (Mountain Division); Table HC14.6.
Nebraska	82.8%	Used NPPD data - Tri-State data seems low compared to other mid-west saturation rates.	82.8%	Information from Joel Young at Nebraska Public Power District (NPPD). He mentioned that Res. Central A/C penetration in NPPD's service area was 82.8% in 2006.
			22.6%	Tri-State: Jim Spiers provided data for Tri-State's 4 states from a "recent residential end-use survey of our 44 Members in Colorado, Wyoming, Nebraska and New Mexico."
Nevada	86.8%	Assume same as AZ based on CDD	42.1%	2005 RECS data (Mountain Division); Table HC14.6.
New Hampshire	12.7%	One data source	12.7%	2005 RECS data (New England Division), Table HC11.6.
New Jersey	55.0%	Used Brattle data - more current	55.0%	Atlanta City Electric AMI business case filing
			45.7%	American Housing Survey (AHS) for the Northern New Jersey Metropolitan Area: 2003, U.S. Census Bureau.
New Mexico	42.0%	One data source	42.0%	2005 RECS data (Mountain Division), Table HC14.6.
New York	16.7%	Average of all data	12.0%	Source: Knowledge Networks, 2007 Electric Forecasting Residential Customer Research, Summer 2007, Prepared for ConEdison, p. 19.
			23.6%	American Housing Survey (AHS) for the Buffalo, NY Metropolitan Area: 2002, U.S. Census Bureau.
			16.4%	American Housing Survey (AHS) for the NY City Metropolitan Area: 2003, U.S. Census Bureau.
			15.0%	2005 RECS data from EIA.
North Carolina	84.4%	One data source	84.4%	American Housing Survey (AHS) for the Charlotte Metropolitan Area: 2002 (also including part of SC), U.S. Census Bureau.
North Dakota	51.0%	Average of RECS and Minnesota CAC % - using only RECS data seems high compared to CDDs. Minnesota has similar CDDs data.	70.9%	2005 RECS data (West North Central Division), Table HC12.6.
Ohio	62.9%	Average of all data - factors in all values given the range of values.	51.3%	American Housing Survey (AHS) for the Cleveland Metropolitan Area: 2004, U.S. Census Bureau.
			75.3%	American Housing Survey (AHS) for the Columbus, OH Metropolitan Area: 2002, U.S. Census Bureau.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
			62.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Oklahoma	84.2%	One data source	84.2%	American Housing Survey (AHS) for the Oklahoma Metropolitan Area: 2004, U.S. Census Bureau.
Oregon	38.0%	Used PGE Customer Data - more current	28.0%	American Housing Survey (AHS) for the Portland, OR Metropolitan Area: 2002, U.S. Census Bureau.
			38.0%	PGE Customer Data 2007.
Pennsylvania	49.8%	Weighted average based on AHS housing stock from each area	48.4%	American Housing Survey (AHS) for the Philadelphia Metropolitan Area: 2003, U.S. Census Bureau.
			52.3%	American Housing Survey (AHS) for the Pittsburg Metropolitan Area: 2004, U.S. Census Bureau.
Rhode Island	12.5%	One data source	12.5%	American Housing Survey (AHS) for the Providence, Pawtucket, Warwick Metropolitan Area: 1998, U.S. Census Bureau.
South Carolina	84.4%	One data source	84.4%	American Housing Survey (AHS) for the Charlotte Metropolitan Area: 2002 (also including part of SC), U.S. Census Bureau.
South Dakota	70.9%	One data source	70.9%	2005 RECS data (West North Central Division); Table HC12.6.
Tennessee	81.4%	One data source	81.4%	American Housing Survey (AHS) for the Memphis Metropolitan Area: 2004 (also including parts of AR, MS), U.S. Census Bureau.
Texas	80.0%	RECS data	77.9%	American Housing Survey (AHS) for the San Antonio Metropolitan Area: 2004, U.S. Census Bureau.
			92.1%	American Housing Survey (AHS) for the Dallas, TX Metropolitan Area: 2002, U.S. Census Bureau.
			87.0%	American Housing Survey (AHS) for the Arlington, TX Metropolitan Area: 2002, U.S. Census Bureau.
			80.0%	2005 RECS data from EIA.
Utah	42.1%	One data source	42.1%	2005 RECS data (Mountain Division), Table HC14.6
Vermont	7.2%	One data source	7.2%	FSC study
Virginia	50.2%	One data source	50.2%	2005 RECS data (South Atlantic Division), Table HC13.6.
Washington	28.6%	Average of all data - Northwest Energy value is for the entire NW area, not by state.	50.0%	Single Family Residential Existing Stock Assessment, Northwest Energy Efficiency Alliance, Aug 2007.
			7.2%	American Housing Survey (AHS) for the Seattle-Everett Metropolitan Area: 2004, U.S. Census Bureau.
West Virginia	50.2%	One data source	50.2%	2005 RECS data (South Atlantic Division), Table HC13.6.
Wisconsin	62.0%	Average of all data - factors in all values given the range of values. CDDS in WI is on the low end.	72.0%	Central Air Conditioning in Wisconsin, Energy Center of Wisconsin, May 2008.
			51.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			53.1%	American Housing Survey (AHS) for the Milwaukee, WI Metropolitan Area: 2002, U.S. Census Bureau.
			72.0%	Information from Harvey Dorn at Alliant Energy. Note that this data is for SF homes only.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Wyoming	42.0%	One data source	42.0%	2005 RECS data (Mountain Division), Table HC14.6.

g) AMI Deployment Schedule by State

Advanced metering is a necessary technology to support price-responsive demand response for mass-market customers. However, having advanced meters is a necessary but not sufficient condition to support price-responsive demand response—a utility also needs a meter data management system (MDMS) and billing system that will support price-responsive demand response options. Quite often, utilities install meters that qualify as advanced meters in that they gather hourly or sub-hourly data daily, but use them as an AMR system to produce monthly meter reads—they do not install the MDMS and billing systems needed to support wide scale price-responsive demand response. A notable example is PPL, which completed its AMI deployment around 2004 and, until recently, had the only large scale AMI system in the country that was generating hourly data on all customers on a daily basis. However, it wasn't until 2008 that the company installed an MDMS system capable of supporting widespread use of price-responsive demand response. Similarly, many small cooperatives and municipalities have AMR or AMI meter systems that can deliver hourly data (although not necessarily daily) but, currently, these systems are almost universally being used only to support monthly meter reads. Without an MDMS system designed to clean and manager hourly data, these small installations can not support wide spread use of price-responsive demand response. The AMI deployment scenarios described below recognize that more than just metering is needed to support price-responsive demand response. The deployment time lines for each scenario are based on the understanding that only systems that have MDMS and billing systems are considered AMI for purposes of supporting demand response potential.

Two AMI deployment scenarios were developed for each state.

- The "Full Deployment" scenario is used to support the Achievable Participation and Full Participation demand response scenarios and assumes that all utilities will have AMI meters in place for all customers, along with the MDMS and billing systems required to support price-based demand response, by the end of the forecast horizon, 2019. Deployment timing is based on a set of assumptions described below, and varies significantly across states based on current plans, the mix of utilities in each state, and other factors.
- The "Partial Deployment" scenario is used to support the Expanded BAU potential scenario and includes AMI deployment plans for each state based largely on a continuation of current trends. It includes utilities that already have or are currently deploying AMI systems and other utilities that, based on a variety of data sources summarized below, have expressed interest in or are believed to have a higher probability of installing such systems over the next ten years.

These two alternative scenarios should not be considered forecasts of actual AMI meter and system deployment. The full deployment scenario is predicated on the assumption that all customers will have smart meters by the end of the ten-year forecast horizon. This assumption is combined with a variety of information and assumptions that drive the likely sequence of installations across utilities in a state and across states that are described below. The partial deployment scenario is probably closer to what might actually occur, but it is not a true forecast, since a true forecast would require conducting business cases on hundreds or perhaps thousands of utilities and an assessment of the likely political and other barriers to deployment in each state. Such work is significantly beyond the scope of this analysis. Even if such work could be completed, it would be subject to change frequently due to some of the factors outlined below. The AMI deployment scenarios presented here should be considered a reasonable starting point for each state based on expert judgment and publicly available information about plans and interest. The demand response potential model has been intentionally set up so that alternative deployment scenarios can easily be substituted.

In addition to limited time and money, one of the primary reasons why the demand response potential estimates are based on AMI deployment scenarios rather than forecasts is that the experience over the last five years illustrates well how difficult it is to forecast AMI activity. The rate of AMI investment depends on a wide variety of factors that are constantly in flux, including federal tax and grant policy, state regulatory policy, technology evolution and testing, and fundamental business case economics, among others. The key forecasting challenges include, but are not limited to:

1. Actual deployment of AMI systems depends importantly on state regulatory policy. Unless regulated utilities anticipate that AMI investments will reduce overall revenue requirements, they will be reluctant to undertake those investments without firm indications from state regulators that such investments will be considered prudent. Thus, regulatory commissions can retard or advance the deployment of AMI within a state by the prudence and clarity they provide. However, forecasting state regulatory commission viewpoints on AMI is extremely difficult because most states have not formulated firm policy and because policy goals within each state are evolving, causing regulatory positions to fluctuate.

2. Federal policy can and does operate to change the basic revenue requirements of AMI. The 2007 change in tax code to identify AMI assets as ten-year, instead of twenty-year, property for tax purposes had a significant impact on improving business case economics. By authorizing funds to support up to 50 percent matching investment funds for Smart Grid and AMI projects, the Federal government has provided further stimulus in the recent American Recovery and Reinvestment Act of 2009. However, future federal AMI initiatives are tied to the economic situation, policies toward greenhouse gas emissions, and transmission grid management policies, and are extremely difficult to anticipate in the future years leading up to 2019.

3. There are a variety of AMI technologies available in the market place, but some of the features and dimensions of these technologies are currently evolving. This on-going evolution makes it difficult for utilities that want to see a fully-deployed system in operation to make a decision to proceed, even if their interest is strong. For example, home-area-networking to support in-home displays and integrated under-glass service disconnection switches are of increasing interest to utilities, but large-scale deployments of these AMI capabilities are not yet observable. Consequently, translating utility stated interests into expected AMI deployment dates is very difficult and depends on specific utility risk profiles.

4. The fundamental economics of AMI deployment varies significantly from utility to utility. Some of the key factors that influence the cost-effectiveness of demand response are:

    a. The higher the current meter reading costs, the more likely utilities are to adopt AMI, but current meter reading costs vary significantly from utility to utility as a result of automation capital currently invested (e.g., drive-by or fixed network AMR), the presence or absence of associated natural gas meters, the prevailing wage levels in the service territory, and the observed meter density (meters per square mile) in the service territory.

    b. Some utilities have substantial field activity related to off-cycle billing reads and service connections and disconnections, while other utilities have minimal field activities in these areas. AMI systems can create dramatic cost savings in these areas. Thus, this activity can be extremely significant in creating benefits to offset AMI costs so it creates important variability in the business case analysis.

    c. Theft of service can be a major consideration for some utilities, and AMI can be very helpful in identifying and reducing theft. For these utilities where theft is important, and where AMI can be used to reduce theft, the cost/benefit calculation will be much more positive, raising the chances that AMI will be implemented.

    d. All utilities seek to reduce estimated and delayed bills, and AMI can help with this goal in a very significant way. However, the number and percentage of estimated and delayed bills varies significantly from utility to utility, as does the importance of reducing them, so that it can be very difficult to predict specific utilities that will gain the most from AMI.

Because the benefits and costs of AMI can be so utility-specific, it is difficult to forecast where positive business cases will be found without detailed, utility-specific analysis, which in turn makes it difficult to forecast which utilities will proceed to implement AMI first. The alternative approach taken here involves the following steps:

1. Six data sources were obtained and examined to determine the most current status of or interest in AMI by hundreds of utilities in the United States. The data sources are listed below:

    a. In a report to the GridWise Alliance (The U.S. Smart Grid Revolution: KEMA's Perspectives for Job Creation, December 23, 2008), KEMA summarized their assessment of major AMI projects and their respective deployment schedules.

    b. In a 2008 survey of utilities, FERC asked a series of questions designed to identify current installations and future interest and plans for installing AMI.

    c. In a January 2008 evaluation of AMI initiatives Utilipoint compiled a list of utilities either implementing or in the process of implementing AMI.

    d. The Enernex Smart Meter Data for the California Energy Commission is a compilation of utilities with active projects or interest in AMI, using a map database format created by the Energy Retail Association.

    e. FERC's annual staff reports on Demand Response and AMI identify particular utilities with plans to deploy AMI systems (Assessment of Demand Response and Advanced Metering 2007, September, 2007, and Assessment of Demand Response and Advanced Metering, December, 2008).

    f. The Institute for Electric Energy Efficiency has released their recent survey of Smart Meter Deployment, Utility-Scale Deployment of Smart Meters, April, 2009.

2. Relevant information from all six data sources was merged into the Form EIA-861, File 2 database, which essentially provides a complete census of all utilities in the country and a mapping of utilities into states. The File 2 data were also used to categorize utilities into size strata and to identify any utilities where no information about AMI status or interest was contained in any of the other data sources.

3. The merged data from step 2 provided a profile of the AMI status of each utility and also a convenient way of identifying situations where different data sources provided contradictory information. In situations where there were internal contradictions, the expert knowledge of the team was used to judge which data was likely to be most accurate.

4. Based on the information above, each utility was assigned to one of the eight classification groups described in Table D-9.

Table D-9: Classification of Utilities by AMI Status

Classification of Utilities by AMI Status		
Category	**Utilities**	**Customers**
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI within two years	5	2.9 million
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI over the next five years.	32	34.9 million
Utilities with more than 100,000 customers (or their affiliates) that have fixed-network AMR systems in place	28	15.6 million
Utilities with more than 100,000 customers (or their affiliates) that appear to have some interest in deploying AMI	63	39.6 million
Utilities with more than 100,000 customers that have given no indication of having interest in deploying AMI	85	20.9 million
Utilities with 10,000-100,000 customers that indicated interest in AMI in the FERC survey	122	3.9 million
Utilities with 10,000 – 100,000 customers that did not indicate interest in AMI in the FERC survey	660	17.5 million
Utilities with less than 10,000 customers	2,540	5.8 million
All Categories	**3,535**	**140.0 Million**

5. The final step in the process involved producing judgmental assessments of the likelihood that each utility will deploy AMI and the time period over which it is likely to be deployed in each of the two deployment scenarios. The probabilities and deployment schedules for each category are summarized in Table D-10.

Table D-10: Assumed Probability and Schedule for Utilities Underlying Each AMI Deployment Scenario

Assumed Probability and Schedule for Utilities Underlying Each AMI Deployment Scenario				
Category	Full Deployment	Partial Deployment	Deployment Start	Deployment End
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI within two years	100%	100%	2009	2011
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI over the next five years.	100%	100%	2009	2013
Utilities with more than 100,000 customers (or their affiliates) that have fixed-network AMR systems in place	100%	67%	2014	2019
Utilities with more than 100,000 customers (or their affiliates) that appear to have some interest in deploying AMI	100%	50%	2014	2019
Utilities with more than 100,000 customers that have given no indication of having interest in deploying AMI	100%	25%	2014	2019
Utilities with 10,000-100,000 customers that indicated interest in AMI in the FERC survey	100%	50%	2014	2019
Utilities with 10,000 – 100,000 customers that did not indicate interest in AMI in the FERC survey	100%	25%	2016	2019
Utilities with less than 10,000 customers	100%	5%	2017	2019

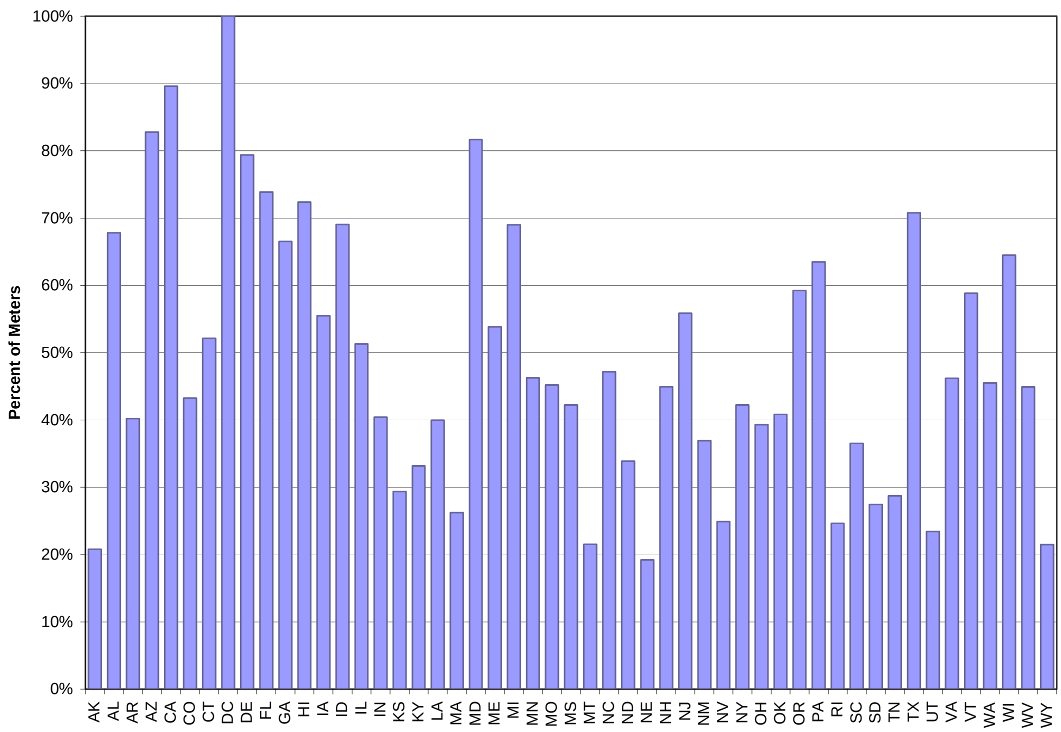
For utilities with automated meter reading systems in place, we assigned a start year and an end year for AMI deployment specific to each utility, based on the age of the automated meter reading system currently in place.

The information and assumptions summarized above lead to different meter deployments for each state and different rates of deployment nationally across the scenarios. Table D-11 shows the annual and cumulative deployment for each forecast year for the two scenarios. Figure D-5 shows the percent of meters in each state that would be AMI meters by the by the end of the forecast period for the partial deployment scenario.

Table D-11: Annual and Cumulative Deployment for Each Forecast Year under EBAU and AP/FP Scenarios

	Partial Deployment Scenario (Used in Expanded BAU Potential)		Full Deployment Scenario (Used in Achievable & Full Participation Scenarios)	
Year	Annual Installations	Cumulative Installations	Annual Installations	Cumulative Installations
2009	7,949,249	7,949,249	7,949,249	7,949,249
2010	8,157,557	16,106,806	8,260,157	16,209,405
2011	8,157,557	24,264,363	8,260,157	24,469,562
2012	8,197,899	32,462,262	8,796,464	33,266,026
2013	8,197,899	40,660,160	8,796,464	42,062,490
2014	6,180,478	46,840,638	13,241,914	55,304,404
2015	6,039,977	52,880,615	13,032,212	68,336,616
2016	6,231,172	59,111,787	16,053,354	84,389,970
2017	6,895,117	66,006,904	19,005,862	103,395,832
2018	7,002,218	73,009,122	18,846,010	122,241,842
2019	6,827,310	79,836,432	18,744,805	140,986,647

Figure D-5: Percent of Meters in State That Are AMI Meters in 2019



Demand Response Program Related Data

a) Business-As-Usual (BAU) Demand Response Potential Estimation

The demand response potential estimation for the Business-As-Usual (BAU) scenario was developed with 2008 FERC Demand Response Survey data[127] , using the following four steps:

1. Classification of Programs: The first step was to classify programs reported in the FERC Survey database to the program categories being considered in estimation of the potential: Direct Load Control (DLC) Programs, Interruptible Programs, Pricing Programs, and 'Other Types of DR Programs'. This classification was based on information provided in the FERC survey related to 'Program Name' and 'Program Description'.

2. Assignment of Programs to C&I Rate Classes: The next step was to assign demand response programs targeted toward C&I customers to the small, medium, and large rate classes. The survey database indicated whether a demand response program was being offered to commercial and/or industrial customers. For all such programs being offered to C&I customers, peak load per customer was estimated using program enrollment data in the survey. The survey database reported the ‘Number of customers enrolled’ and the ‘Load enrolled’ for each demand response program. This data was used to calculate the load enrolled per customer. If the per customer load enrolled was less than or equal to 20 kW, the program was assigned to the small C&I rate class. For medium C&I customers, the enrolled load per customer ranged between 20-200 kW, while for large C&I customers the value was greater than 200 kW.

3. Aggregation of Survey Data: The Survey database provides data on ‘No. of Customers Enrolled', 'Load Enrolled', and 'Potential Load Reduction' for demand response programs reported by utilities. Data for these items were aggregated to the state level to come up with estimates for these items by rate class and program type[128]. Certain adjustments were made to the 2008 Survey data to obtain the BAU estimate of the load reduction potential. These adjustments are described in Chapter III of the report in a sidebar titled ‘Benchmarking the BAU Estimate’. In addition, the total load reduction potential reported by ISO-NE and PJM in the FERC Survey database had to be allocated to the states served by these entities.[129]

The BAU potential estimation results are included in ‘Table 5- Known DR Participation’, which appears in the ‘Inputs Database’ worksheet of the Demand Response Potential Estimation model.

[127] For details related to the FERC 2008 Demand Response Survey, please refer to the FERC Staff Report titled ‘2008 Assessment of Demand Response and Advanced Metering’. It should be noted that only those programs that reported a positive 'Potential Load Reduction' in the database were included in developing the BAU forecast.

[128] It should be noted that only those programs that reported a positive 'Potential Load Reduction' in the database were included in developing the BAU forecast.

[129] In the FERC survey database, ISO-NE and PJM reported their entire load reduction potential only against a particular state. ISO-NE reported its entire potential against Connecticut, while PJM reported its entire potential against DC. For ISO-NE, the potential reported was allocated across all states falling under ISO-NE’s jurisdiction, based on actual data obtained from ISO-NE. For PJM, the load reduction potential was distributed across all states served by PJM, in the proportion of load served by PJM for these states.

b) Current Participation in Demand Response Programs

The methodology for determining current participation rates in demand response programs varied by type of program. For estimating participation rates in Residential Direct Load Control programs (CAC cycling only), a distinct approach was used as compared to what was followed for the remaining demand response program types considered in our analysis.

The bullet points below describe the approaches used for: 1) residential DLC programs; 2) other remaining demand response programs.

- **Participation Rate Estimation for Residential DLC Programs**: The FERC survey database was used as the primary source of information for estimating current participation rates in residential DLC programs (for the case of CAC only). For each state, the total 'Number of Customers Enrolled' for a particular demand response program type was obtained by aggregating utility data for the state. This was then divided by the 'Total Number of Customers' developed for each state by rate class to arrive at participation rate estimates by program type and rate class for each state.

  An assessment was also carried out to determine how representative the FERC survey data were for estimating 'Participation Rate' for the entire state. If more than 50% of the state's residential population was being covered by the FERC survey, the FERC survey data were considered to be representative of the state. On the other hand, if less than 50% of the residential customer population was represented, information from outside sources was obtained to arrive at 'best' estimates for a state. Outside information sources included utility websites, utility program reports and regulatory filings, and direct contact with utilities.

- **Participation Rate Estimation for all other Demand Response Programs**: The estimation of participation rates for all other demand response programs relied on FERC survey data, wherever information was available on number of customers enrolled in different demand response programs. The participation rate was estimated both as 'percentage of customers' as well as 'percentage of load'. Participation rate as 'percentage of customers' was obtained by aggregating 'No. of Customers Enrolled' data from the FERC survey for a particular type of demand response program and dividing that by the corresponding 'Total No. of Customers' in the state by rate class. Similarly, participation rate as 'percentage of load' was obtained by aggregating 'Total load enrolled' data from the FERC survey for a particular type of demand response program and dividing that by the corresponding 'Total Load' in the state by rate class.

Participation rate estimations by demand response program type and by Rate Class appear in the 'Inputs Database' worksheet of the Demand Response Potential Estimation model.

c) Impacts from Non-pricing Programs

The methodology used to estimate impacts of demand response programs varied by the type of program. The bullet points below describe the approaches used for: 1) DLC programs (CAC control only); 2) Interruptible and 'Other DR' programs;

1) Impact Estimation for DLC Programs (CAC control only): For arriving at 'best estimates' of unit load reduction impacts for residential DLC programs, a combination of information sources was employed. The sources included FERC survey database information, which was used for estimating impacts by dividing the 'Potential Load Reduction' value by the 'Number of Customers Enrolled'. In addition, specific estimates from utility programs outside the FERC survey database were obtained along with DLC program evaluation reports. For states where information was missing, a default value of 1 kW reduction per customer was assumed. Per-customer load reduction impacts for C&I customers from DLC programs were estimated by applying a multiplier to the per customer impact for residential customers.[130]

2) Impact Estimation for Interruptible and 'Other DR' programs: For these programs, the FERC survey database information was used for arriving at load reduction estimates. The 'Potential Load Reduction' as a percentage of the 'Enrolled Load' by demand response program type was used to estimate demand response program impacts.

d) Impacts from Pricing Programs

The Achievable Participation and Full Participation potential estimates rely heavily on price-based demand response options, specifically on dynamic tariffs that deliver high price signals on relatively few high-demand days when demand response benefits are greatest. Estimates of the load impact associated with pricing options are based on variables known as price elasticities. Economists define the "own" price elasticity as the percentage change in the quantity purchased of a good or service divided by the percentage change in the price of that good or service. There is a similar concept, known as the elasticity of substitution, which summarizes the relationship of two goods or services that are substitutes for each other. The elasticity of substitution is equal to the percentage change in the ratio of the quantities purchased of two goods to the ratio of the prices of the two goods. Put another way, the elasticity of substitution summarizes the rate at which consumers substitute one good for another based on the relative prices of the two goods.

In the case of electricity demand, if prices are higher at one time of day relative to another, consumers may be willing to shift their load from the high priced to the low priced period. An example would be a consumer shifting the timing of their laundry from the peak to the off peak period. Alternatively, or in addition, a consumer might just forgo some energy use during the high price period. An example would be switching off lights during high priced periods—consumers don't use more lighting during low priced periods because they used less during high priced periods.

One approach to estimating how electricity demand would change in response to time varying prices involves estimating a two-equation demand system, where one equation determines the rate at which consumers substitute off-peak energy use for peak-period energy use and the second equation estimates the overall demand for energy. In combination, the two equations can predict the change in energy use in each time period as consumers move from non-time varying to time-varying prices. This is the approach that underlies the estimates of time-based price response in the demand response potential model.

A variety of pricing experiments and other studies have been conducted that allow for estimation of demand models and price elasticities such as those described above. These studies show that price responsiveness for residential customers varies across regions based in part on differences in the use of air conditioning. Climate differences can also impact price responsiveness, as can the presence or absence of enabling technology such as programmable communicating thermostats and other load control devices. Price responsiveness also differs between residential and non-residential customers with residential customers generally being more price responsive than non-residential customers. These factors have been taken into account in developing estimates of price response that reflect variation in the characteristics of customers across states. The remainder of this section summarizes how state-specific estimates of price response were developed in this project.

Residential

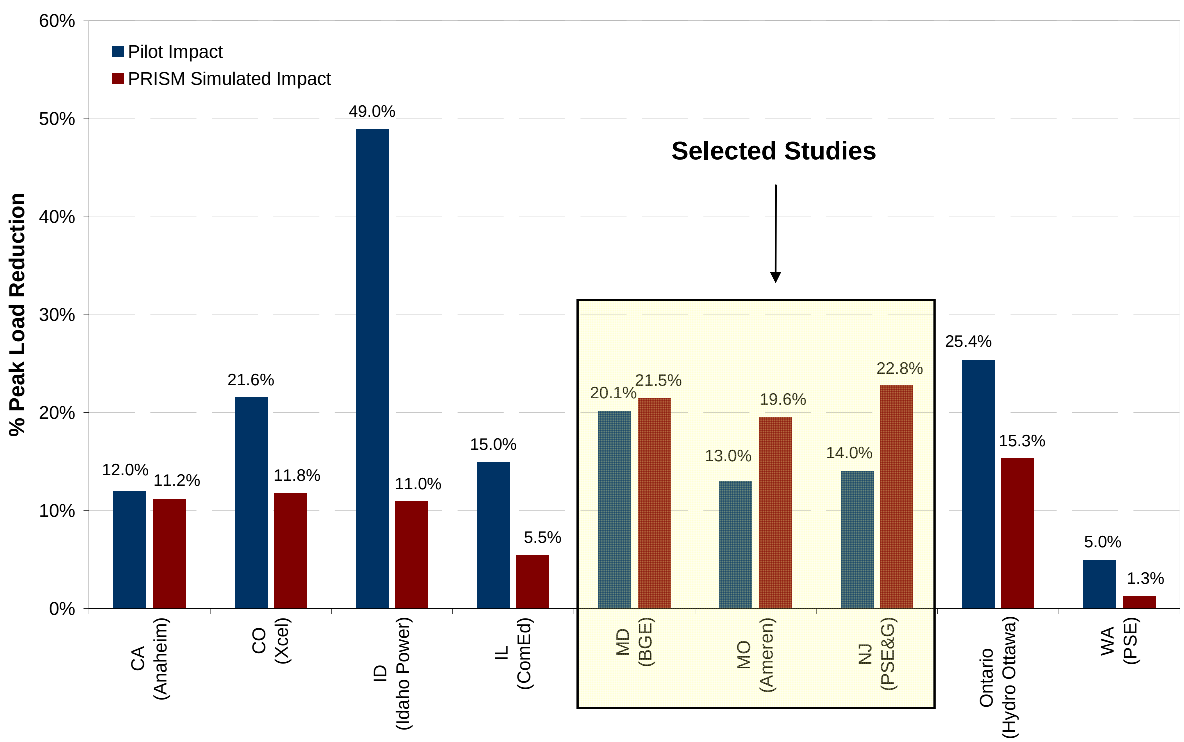
The California Statewide Pricing Pilot (SPP) produced estimates of price elasticity for residential customers that captured variations in customer price responsiveness across four different climate zones in the state. These estimates were codified in the Pricing Impact Simulation Model (PRISM) which allows

[130] This multiplier was based on estimations of the number of cycling switch devices required for Direct Load Control for C&I customers.

price elasticities to vary as a function of a zone's saturation of central air condition (CAC) equipment and weather conditions.[131] Specifically, it was found that zones with higher CAC saturation (which were also the hotter climate zones) were more price elastic than zones with low CAC saturations (which were also the milder climate zones). CAC saturation was found to be a key driver of differences in price responsiveness across the zones. These findings made it possible to express price elasticity as a function of CAC saturation, allowing the PRISM results to be projected to other regions of the country.

However, this projection needs be interpreted as the first step in a two-step process. Dynamic pricing pilots have been conducted in several locations and when the results of PRISM, calibrated to the CAC saturations were compared with those of pilots conducted in those regions, it was found that PRISM did not explain all the variation in pilot results. Figure D-6 summarizes a comparison for nine recent residential dynamic pricing pilots.[132]

Figure D-6: Comparison of Impacts from Recent Pricing Pilots to Calibrated PRISM Simulations



It is apparent that, even when accounting for CAC saturation and the price ratio tested in a given pilot, PRISM does not exactly replicate the pilot's results. Given the state-specific nature of this study, it is necessary to capture these regional differences. However, while each of the pilots in Figure D-6 draws some valuable conclusions about customer price response, some judgment must be exercised in determining whether to extrapolate their findings to a larger population beyond the participants of the pilot. The details of each pilot were carefully reviewed to determine which should be considered when adjusting the PRISM simulated impacts to account for regional differences. Ultimately, six of these nine

[131] The experiment also identified the relationship between price elasticity and average temperature. However, the effect of temperature on price response is much less significant than that of CAC saturation. For the purposes of this study, the temperature effect is held constant across regions.

[132] For more information on the key findings of recent dynamic pricing pilots, see Ahmad Faruqui and Sanem Sergici, "Household response to dynamic pricing of electricity: A survey of the experimental evidence," January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

pilots were excluded from the analysis. Reasons for excluding these pilots are summarized in Table D-12.

Table D-12: Pilot Impacts Excluded from Assessment

Pilot	Reason for Exclusion
California (Anaheim Public Utilities)	Results of the more comprehensive California SPP are being used for California, and the Anaheim impacts are very similar
Colorado (Xcel)	The study identifies issues with self-selection bias which potentially result in an overstatement of the impacts
Idaho (Idaho Power)	The mix of pilot participants was not considered to be representative of the larger population of utility customers
Illinois (ComEd)	Impacts are based on a residential RTP rate and there is not enough available data to accurately determine the impact on average critical peak consumption (results presented in Figure D-6 are during the single highest hour of peak demand)
Ontario (Hydro Ottawa)	For the purposes of this state-specific study, pilots are limited to those conducted in the United States; this pilot could be included in studies of a broader geographical scope but the large standard errors reported in the pilot may preclude extrapolation of results to other regions
Washington (PSE)	The pilot tested a non-dynamic, traditional TOU and that too with a very low peak-to-existing price ratio (1.17), preventing the results to be used in this study

Based on this review, impacts from three of the nine pilots on which data were available were used to further refine the simulations derived from PRISM. Those pilots were conducted in Maryland by BGE, in Missouri by Ameren, and in New Jersey by PSE&G. In each of these pilots, actual customer price response was found to be lower than that simulated by PRISM. A likely explanation for this is that PRISM does not account for the effect of humidity. The California SPP was conducted across zones with a wide range of average temperatures but all the zones lay in a state with relatively low humidity. As a result, the model results would not reflect the likely conclusion that customers in more humid regions would be less responsive to dynamic pricing given the higher loss of comfort that they would experience by turning down their air conditioner on hot summer days.

In Maryland, Missouri, and New Jersey, PRISM-simulated peak demand reductions were scaled back to equal the lower impacts that were observed in these three pilots. In addition, adjustments were made for all states east of the Rocky Mountains to account for the humidity effect observed in the three pilots. PRISM-simulated residential impacts for these states were derated by 20 percent, which is the approximate midpoint of the difference between the California SPP impacts and that of the three previously described pilots.

PRISM allows separate impact estimates to be developed for customers who are offered dynamic pricing in conjunction with enabling technologies. Specifically, for the purposes of the Achievable and Full Participation demand response scenarios, it is assumed that residential customers would be offered a programmable communicating thermostat whenever the incremental effect of this enabling technology is likely to be large enough to make such a device cost effective. The California SPP captured the price elasticity of customers who were both enrolled in dynamic pricing and equipped with programmable communicating thermostats. As a result, these elasticities were used in California and in states west of the Rockies. The PRISM simulations were scaled back for states east of the Rocky Mountains in the same manner as for those customers who did not have the enabling technologies.

Small and Medium C&I

Price elasticities for Small and Medium C&I customers were also estimated during the California SPP. Small C&I customers provide peak reductions of less than one percent even at high price ratios. Medium C&I customers were found to be somewhat more responsive, but less so than residential customers. There are no results from other studies upon which to base any regional variation in these impacts and so the California SPP results were held constant across the states. Price elasticity with enabling technology also comes directly from the California SPP. For both the Small and Medium C&I classes, customers are assumed to be offered programmable communicating thermostats.

Large C&I

Large C&I customers were not included in the California SPP nor are they included in any other pricing pilots. Therefore, price elasticity data for this customer class is limited to a few full-scale implementations in the Northeastern U.S. Much of this information was summarized in a recent study carried out by the Demand Response Research Center.[133] According to this study, the elasticity of substitution could be as high as -0.15 and the daily elasticity could be as high as -0.20. Both estimates varied greatly by sector and rate offering. There is a significant amount of uncertainty in these estimates and they are based on a limited number of participants, so for the purposes of the Assessment they have been scaled down to avoid potentially overstating the impacts.[134] This is an area in which further research is warranted.

There is very limited information on the potential for demand response when customers in this class are equipped with enabling technologies. For the purposes of the Assessment, it is assumed that these customers would be offered automated demand response, a technology that would allow for a coordinated, automated curtailment of electricity consumption at a number of customer end uses. The best available information on the potential impacts of automated demand response comes from a recent study by the Demand Response Research Center.[135] Large C&I customers at all three of California's investor-owned utilities were equipped with the technology, and on average the incremental additional reduction in peak demand was found to be at least 13 percent, or an 86 percent increase over the anticipated response to dynamic pricing in the absence of the technology. It is this incremental increase of 86 percent that was used to represent the incremental impact of enabling technology for the Large C&I class in the Assessment.

It should be noted that, while the DRRC study represents the best available information on this topic, the findings are based on a technology demonstration project rather than on the results of a scientific experiment. As a result, there is significantly more uncertainty in these estimates. This is also an area where further research is warranted.

Assumed Elasticities

The final elasticities used in the Assessment are presented in Table D-13.

Table D-13: Assumed Elasticities by Customer Class

	Type of Elasticity	Res (No CAC)	Res (CAC)	Small C&I	Medium C&I	Large C&I
Without Enabling Technology	Critical Day Substitution	-0.0472	-0.1383	0.0000	-0.0412	-0.0500
	Critical Day Daily Elasticity	-0.0330	-0.0487	0.0000	-0.0250	-0.0200
	Normal Weekday Substitution	-0.0425	-0.1336	0.0000	-0.0493	-0.0500
	Normal Weekday Daily Elasticity	-0.0354	-0.0511	0.0000	-0.0250	-0.0200
	Weekend Daily Elasticity	-0.0354	-0.0511	0.0000	-0.0250	-0.0200
With Enabling Technology	Critical Day Substitution	-0.0472	-0.3523	-0.0892	-0.0815	N/A
	Critical Day Daily Elasticity	-0.0330	-0.0677	-0.0250	-0.0250	N/A

133 Goldman, C., Hopper, N., Bharvirkar, R., Neenan, Cappers, P. August 2007. A Methodology for Estimating Large-Customer Demand Response Market Potential, Lawrence Berkeley National Laboratory Report No. LBNL-63346, presented at: IEPEC Conference, Chicago.

134 These elasticities were recently used in a study for the Demand Response Research Center and are further discussed in: Ahmad Faruqui, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009.

135 See "Automated Demand Response for Commercial and Industrial Facilities: A Progress Report to the CPUC," prepared by the Demand Response Research Center, December 2007. Also, Wikler, G., et. al., "Enhancing Price Response through Auto-DR: California's 2007 Implementation Experience," Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, August 2008

For states east of the Rockies, residential impacts derived from PRISM with and without technology are scaled back by 20 percent. Impacts for Maryland, Missouri, and New Jersey are scaled back by seven percent, 34 percent, and 39 percent, respectively, to equal results determined by pilots in those states (see discussion above). Large C&I impacts are increased by 86 percent to represent the impacts of automated demand response.

The price elasticities summarized above for residential customers produce quite different percent reductions across states as a function of the variation in climate and air conditioning saturations. There are also differences in the estimated percent reduction in peak period energy use based on differences in the assumed ratio of prices during the peak period. The percent reduction in peak period energy use for residential customers for each state and two price ratios are shown in Table D-14. Note that the relationship between price and energy use is not linear. That is, while the price ratio doubles going from 4 to 1 to 8 to 1, the percent reduction in peak demand increases by less than 100 percent. For example, the doubling of the price ratio in California leads to a 57 percent decrease in peak period energy use.

Table D-14: Percent Reduction in Peak Period Energy Use for the Average Residential Customer

State	CAC Saturation	Percent Peak Period Reduction for 4 to 1 Price Ratio	Percent Peak Period Reduction for 8 to 1 Price Ratio
Alabama	62.00%	9.67%	15.18%
Alaska	2.50%	6.64%	10.57%
Arizona	86.80%	14.28%	22.33%
Arkansas	54.60%	9.15%	14.38%
California	41.00%	10.25%	16.13%
Colorado	47.24%	10.79%	16.97%
Connecticut	26.91%	7.20%	11.37%
Delaware	53.00%	9.04%	14.20%
District of Columbia	56.00%	9.25%	14.53%
Florida	91.00%	11.72%	18.32%
Georgia	82.25%	11.10%	17.37%
Hawaii	17.55%	6.55%	10.36%
Idaho	66.50%	12.49%	19.58%
Illinois	75.00%	10.59%	16.59%
Indiana	74.39%	10.55%	16.52%
Iowa	70.00%	10.24%	16.05%
Kansas	83.68%	11.20%	17.53%
Kentucky	76.00%	10.66%	16.70%
Louisiana	75.49%	10.62%	16.64%
Maine	14.00%	6.30%	9.98%
Maryland	78.00%	12.56%	19.66%
Massachusetts	12.70%	6.20%	9.83%
Michigan	57.22%	9.34%	14.66%
Minnesota	51.15%	8.91%	14.00%
Mississippi	74.72%	10.57%	16.56%
Missouri	87.50%	9.46%	14.80%
Montana	42.10%	10.34%	16.28%
Nebraska	82.80%	11.14%	17.43%
Nevada	86.80%	14.28%	22.33%
New Hampshire	12.70%	6.20%	9.83%
New Jersey	55.00%	7.00%	11.00%
New Mexico	42.00%	10.33%	16.26%
New York	16.75%	7.32%	11.56%
North Carolina	84.35%	11.25%	17.60%
North Dakota	51.00%	8.90%	13.99%
Ohio	62.86%	9.74%	15.27%
Oklahoma	84.16%	11.24%	17.58%
Oregon	38.00%	9.98%	15.72%
Pennsylvania	49.75%	8.81%	13.85%
Rhode Island	12.49%	6.19%	9.81%
South Carolina	84.35%	11.25%	17.60%
South Dakota	70.90%	10.30%	16.14%
Tennessee	81.44%	11.04%	17.29%
Texas	80.00%	10.94%	17.13%
Utah	42.10%	10.34%	16.28%
Vermont	7.20%	5.82%	9.24%
Virginia	50.20%	8.84%	13.90%
Washington	28.62%	9.16%	14.45%
West Virginia	50.20%	8.84%	13.90%
Wisconsin	62.03%	9.68%	15.18%
Wyoming	42.00%	8.27%	13.01%

e) Cost effectiveness analysis

For the purposes of economic screening, the five demand response programs being considered in the analysis can be divided into two broad categories – those that do not require an enabling technology for participation and those that do. The demand response options that do not require an enabling technology for participation were deemed to be cost-effective for all states. For the demand response options that do require an enabling technology for participation, a measure-level economic screen was conducted to assess their cost-effectiveness in each state. The purpose of this preliminary analysis is to determine which states have the critical peak customer loads which would justify the initial costs of enabling technology irrespective of participant rates. The two types of options for which an economic screen was conducted are: 1) Dynamic Pricing with Enabling Technology, and 2) Direct Load Control. This section describes the methodology and the results associated with the economic screening of these two types of demand response options.

Methodology

The economic screen uses a simple version of the Total Resource Cost (TRC) Test that compares the lifetime benefits of the demand response option (i.e., avoided capacity costs) relative to the associated costs to enable each option (i.e., costs related to technology adoption, implementation and delivery, etc.) on a per-participant basis. Inputs for the economic screen include impact estimates per participant by state, capacity costs, equipment costs and implementation costs, as well as economic parameters such as discount and cost escalation rates. The benefits are obtained by multiplying the unit demand reduction for each technology by avoided capacity costs ($/kW) over the ten year time horizon and discounting the dollar savings to a present value equivalent basis. The costs are equal to the equipment and implementation costs per participant.[136] If the benefit-cost ratio is 1.00 or greater, the demand response option is considered cost-effective and is included in the state's Full Participation potential results.

To determine cost-effectiveness associated with the two demand response options, the impact estimates already developed as part of demand response potential estimation were used. The Dynamic Pricing Option without enabling technology is deemed to be cost-effective. Hence this analysis considers only the benefits and costs attributable to the technology component. The enabling technologies included in the analysis are:

- Programmable Communicating Thermostats and remotely-controlled switches for the small and medium load customers, and
- Automated Demand Response technologies for the large load customers.

The equipment type and associated costs are summarized in Table D-15 for the two demand response options by customer class. An additional 15% was added to the equipment costs to represent up-front costs for program development and ongoing costs for implementation and delivery.[137]

Table D-15: Enabling Technology Equipment Costs[138]

Customer Type	Dynamic Pricing		Direct Load Control	
	Equipment	Unit Cost	Equipment	Cost
Residential	PCT	$200	Switch	$200
Small C&I	PCT	$350	Switch	$350
Medium C&I	PCT	$1,050	Auto-DR	$1,050
Large C&I	Auto-DR	$13,500	N/A[139]	N/A

An avoided capacity cost of $75 per kW (representing the investment cost of a gas-fired combustion turbine-generator) was used to derive the avoided cost benefits. This value was escalated at 3% per year for each year beyond 2009. The projected avoided costs were discounted to present value equivalents using a discount rate of 5%.[140]

[136] The cost-effectiveness is not performed at the program-level, therefore the effects of incentives and participation rates are not included in this analysis.
[137] This percentage is commonly used for these types of studies and it based on benchmark experience from actual demand response program implementation nationwide.
[138] The costs are based on vendor estimates and utility program cost data for programs with similar demand response options.
[139] Note that Direct Load Control for large C&I customers was not considered in the analysis.
[140] The assumptions related to avoided capacity costs, cost escalation rates, and discount rates represent commonly accepted estimates for similar analyses conducted in the industry.

Summary of Results

A demand response option with enabling technology is cost-effective and as such passes the economic screen if the benefit-cost (B/C) ratio is 1.00 or higher. Summary results of the economic screen are included in Tables 16 and 17 for Dynamic Pricing with Enabling Technology and Direct Load Control, respectively. The tables list the B/C ratios for each state and indicate the states where the demand response options are cost-effective.

The economic screening results show that Dynamic Pricing with Enabling Technology is a cost-effective option for the majority of states. However, there are a number of states for which it fails the economic screen. The results vary by customer type. Dynamic Pricing with Enabling Technology for residential customers is cost-effective for 42 states (84% of states). The option for small C&I customers is cost-effective for 40 states (80% of states) as well as for the District of Columbia. For the medium C&I customers, the option is cost-effective for 43 states (86% of states) and the District of Columbia, while for the large C&I category it is cost-effective for 45 states (90% of states) and the District of Columbia. The results indicate that Dynamic Pricing with Enabling Technology is cost-effective primarily for those states with high critical peak loads associated with large cooling or other end-use requirements. In particular, this option is highly cost-effective in Arizona and Nevada.

Notable results and observations from the Dynamic Pricing with Enabling Technology screen:

- A state not passing the cost-effectiveness screen does not suggest these programs should not be pursued in that state. The estimates are based on price response using class-average load shapes. Many of the states that did not pass in fact have varying weather characteristics that would lead to different impacts. Some regions might have higher impacts and thus these programs may indeed be cost-effective.
- As the customer class size increases and approaches the large C&I class (starting with the small C&I), more states become cost-effective.
- These trends suggest that as dynamic pricing tariffs are introduced across the country, utilities that are considering adopting one of their own might consider starting with the larger customer classes and gradually introduce the tariffs to the smaller classes once more information is available.
- Careful attention should be given to the economic analysis for these types of programs, particularly when looking at the residential class, which in some regions of the country may not provide the needed level of savings to justify the cost of enablement technologies such as programmable communicating thermostats and automated demand response.

Direct Load Control is a cost-effective demand response option for most states because of the higher per participant savings associated with this option. The analysis showed that Direct Load Control is cost-effective for residential customers in 48 states (96%) and the District of Columbia. The only states for which it is not cost-effective for residential customers are Alaska and Hawaii. Among both small and medium C&I customers, Direct Load Control is cost-effective for all states and the District of Columbia.

Notable results and observations from the Direct Load Control with Enabling Technology screen:

- Most states passed the economic screen. However, for those states that failed the screen, methods of direct load control other than air conditioning might be viable.
- Methods to control water heating and pumping loads may be more viable in these regions.

Table D-16: Economic Screen Results for Dynamic Pricing with Enabling Technology

Dynamic Pricing with Enabling Technology															
Residential				Small C&I				Medium C&I				Large C&I			
Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C
AL	1.93	AK	0.53	AK	1.13	CA	0.80	AK	2.46	ID	0.96	AK	3.04	CT	0.61
AR	1.71	DC	0.95	AL	3.81	CO	0.48	AL	5.93	IL	0.87	AL	2.21	KS	0.94
AZ	2.35	HI	0.67	AR	2.30	CT	0.98	AR	2.86	MA	0.76	AR	2.36	MN	0.97
CA	1.01	IL	0.83	AZ	4.27	FL	0.73	AZ	5.11	MD	0.99	AZ	2.43	NE	0.86
CO	1.18	ME	0.77	DC	2.41	ME	0.52	CA	1.16	ME	0.91	CA	1.64	NH	0.90
CT	1.51	MI	0.83	DE	3.84	MN	0.81	CO	1.24	NH	0.99	CO	2.66		
DE	1.14	MN	0.98	GA	1.38	OK	0.97	CT	1.96	RI	0.98	DC	2.20		
FL	1.44	VT	0.96	HI	1.06	RI	0.69	DC	4.89			DE	2.81		
GA	1.68	WI	0.77	IA	1.04	TX	0.95	DE	3.86			FL	2.05		
IA	1.02			ID	1.00	VT	0.55	FL	1.24			GA	1.78		
ID	2.00			IL	1.85			GA	1.84			HI	2.48		
IN	1.25			IN	1.60			HI	1.39			IA	2.09		
KS	1.38			KS	1.62			IA	1.46			ID	1.88		
KY	1.55			KY	2.66			IN	1.62			IL	1.33		
LA	1.80			LA	3.70			KS	1.35			IN	2.36		
MA	1.09			MA	1.51			KY	5.43			KY	2.83		
MD	1.53			MD	3.31			LA	1.19			LA	2.28		
MO	1.24			MI	1.56			MI	1.48			MA	1.89		
MS	1.84			MO	1.27			MN	1.28			MD	1.79		
MT	1.28			MS	2.22			MO	3.41			ME	1.69		
NC	1.57			MT	3.11			MS	2.41			MI	1.80		
ND	1.28			NC	1.41			MT	4.84			MO	2.21		
NE	1.27			ND	2.44			NC	5.19			MS	3.59		
NH	1.19			NE	1.15			ND	3.98			MT	3.25		
NJ	1.11			NH	1.20			NE	3.95			NC	4.05		
NM	1.00			NJ	1.80			NJ	2.38			ND	1.81		
NV	1.91			NM	1.22			NM	1.89			NJ	1.17		
NY	1.19			NV	3.06			NV	3.47			NM	2.09		
OH	1.10			NY	1.44			NY	2.50			NV	2.75		
OK	1.62			OH	2.16			OH	2.01			NY	2.42		
OR	1.51			OR	1.14			OK	2.15			OH	1.78		
PA	1.04			PA	2.07			OR	2.30			OK	2.30		
RI	1.03			SC	1.93			PA	1.32			OR	2.01		
SC	1.80			SD	2.35			SC	5.30			PA	1.90		
SD	1.16			TN	2.91			SD	2.69			RI	1.16		
TN	1.98			UT	1.24			TN	5.74			SC	5.01		
TX	1.67			VA	1.16			TX	1.46			SD	1.19		
UT	1.32			WA	1.65			UT	2.66			TN	1.11		
VA	1.49			WI	1.03			VA	2.72			TX	6.16		
WA	1.46			WV	1.60			VT	1.50			UT	3.90		
WV	1.41			WY	3.76			WA	3.39			VA	2.09		
WY	1.11							WI	1.87			VT	2.28		
								WV	2.41			WA	2.28		
								WY	2.03			WI	2.31		
												WV	4.23		
												WY	4.58		

Table D-17: Economic Screen Results for Direct Load Control

Direct Load Control											
Residential				Small C&I				Medium C&I			
Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C
AL	5.41	AK	0.00	AK	3.87			AK	3.87		
AR	3.37	HI	0.93	AL	6.18			AL	6.18		
AZ	3.11			AR	3.85			AR	3.85		
CA	1.49			AZ	3.55			AZ	3.55		
CO	1.71			CA	4.90			CA	4.90		
CT	3.30			CO	4.15			CO	4.15		
DC	2.98			CT	3.77			CT	3.77		
DE	2.50			DC	3.41			DC	3.41		
FL	4.11			DE	2.86			DE	2.86		
GA	3.85			FL	4.70			FL	4.70		
IA	1.67			GA	4.40			GA	4.40		
ID	3.14			HI	2.48			HI	2.48		
IL	1.20			IA	6.15			IA	6.15		
IN	3.06			ID	3.59			ID	3.59		
KS	2.71			IL	3.23			IL	3.23		
KY	3.13			IN	3.50			IN	3.50		
LA	3.11			KS	3.10			KS	3.10		
MA	3.11			KY	3.57			KY	3.57		
MD	2.38			LA	3.55			LA	3.55		
ME	1.55			MA	3.55			MA	3.55		
MI	1.43			MD	2.72			MD	2.72		
MN	3.15			ME	3.55			ME	3.55		
MO	4.18			MI	3.90			MI	3.90		
MS	3.11			MN	3.60			MN	3.60		
MT	3.11			MO	4.78			MO	4.78		
NC	3.21			MS	3.55			MS	3.55		
ND	3.11			MT	3.55			MT	3.55		
NE	3.11			NC	3.67			NC	3.67		
NH	3.11			ND	3.55			ND	3.55		
NJ	2.58			NE	3.55			NE	3.55		
NM	1.38			NH	3.55			NH	3.55		
NV	4.02			NJ	2.95			NJ	2.95		
NY	4.25			NM	3.55			NM	3.55		
OH	3.04			NV	4.60			NV	4.60		
OK	3.11			NY	4.86			NY	4.86		
OR	3.11			OH	3.47			OH	3.47		
PA	3.11			OK	3.55			OK	3.55		
RI	3.11			OR	3.55			OR	3.55		
SC	2.31			PA	3.55			PA	3.55		
SD	1.90			RI	3.55			RI	3.55		
TN	3.11			SC	2.64			SC	2.64		
TX	3.44			SD	6.04			SD	6.04		
UT	3.11			TN	3.55			TN	3.55		
VA	3.11			TX	3.93			TX	3.93		
VT	3.11			UT	3.55			UT	3.55		
WA	1.65			VA	3.55			VA	3.55		
WI	1.14			VT	3.55			VT	3.55		
WV	3.11			WA	4.26			WA	4.26		
WY	3.11			WI	3.43			WI	3.43		
				WV	3.55			WV	3.55		
				WY	3.55			WY	3.55		

APPENDIX E. UNCERTAINTY ANALYSIS

The data and assumptions in this Assessment are based on the results of a detailed survey of demand response programs and a comprehensive review of previous research on demand response potential. However, as with any forward-looking assessment, the data and assumptions are uncertain. To represent the magnitude of the impact of this uncertainty, sensitivity analysis has been conducted on the variables that are the key drivers of the potential estimates.

A number of factors contribute to the overall potential for demand response. However, at the highest level the calculation of potential boils down to the following simple equation:

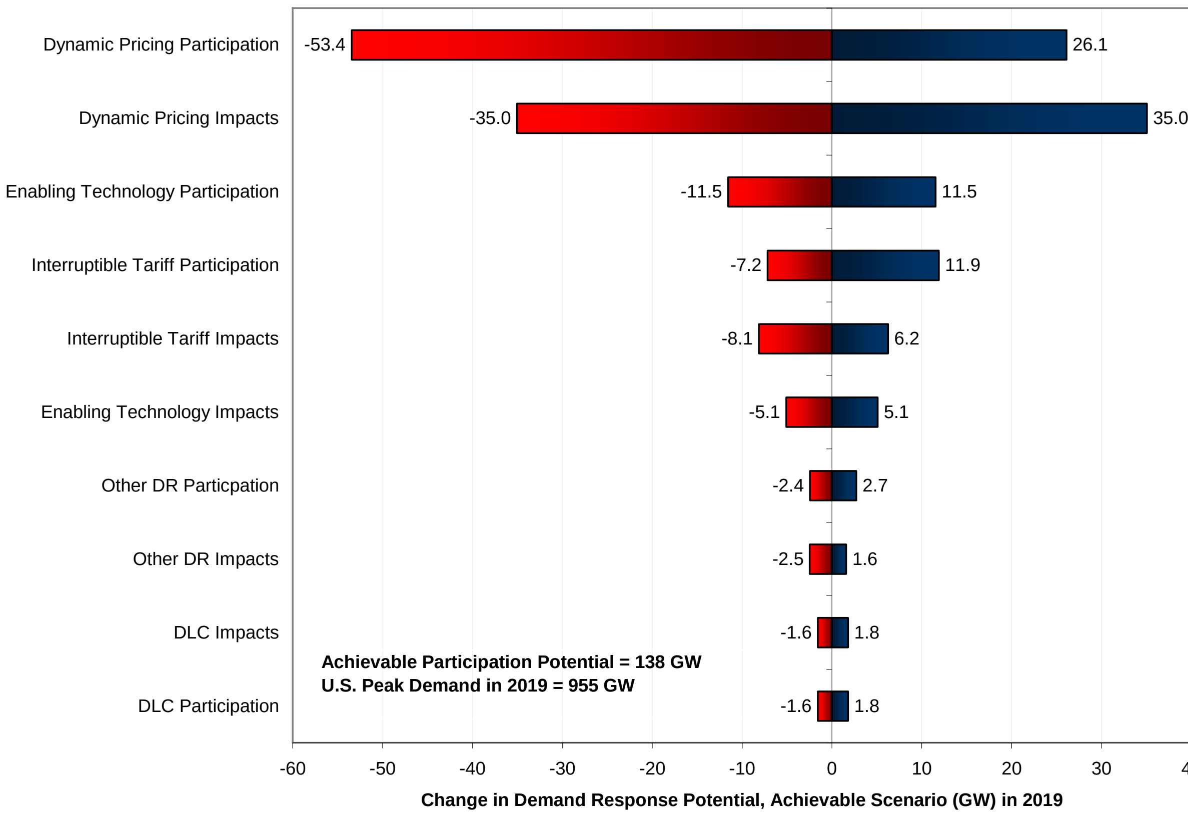
Total demand response potential = # of customers participating in demand response programs ***x*** *peak reduction per participant*

Thus, to develop an understanding of the level of uncertainty in the potential estimates in this Assessment, the two components on the right-hand side of the above equation were chosen as the variables to be tested through sensitivity analysis. For each of the five categories of demand response programs, a high and a low value were chosen for the assumed per-customer impacts and the participation rates. In total, this amounts to twenty new assumptions to be run through the model: 5 program types x 2 values (high and low) x 2 variables (impacts and participation).

To determine the high and low values, each of the model inputs described above were increased by 50 percent (representing the high value) and decreased by 50 percent (representing the low value). This allowed for a consistent comparison across each of the variables in assessing their relative contributions to the uncertainty in the overall potential estimate. The one exception to this is the assumption regarding dynamic pricing participation. Because dynamic pricing is a newly developing program and does not yet have an established history of participation like the other demand response program types, a wider range of uncertainty was used. In the Achievable Participation scenario, the high value for participation was assumed to be 100 percent (representing a scenario where dynamic pricing is the universal rate) and the low value was assumed to be five percent (representing a scenario where dynamic pricing is voluntary and few customers choose to enroll).

The 20 sensitivity assumptions were each run through the model one-at-a-time, while holding all other modeling assumptions constant. The analysis was only conducted for the Achievable Participation scenario, but the approach could be expanded to apply to the other scenarios as well. The results of the model runs can be summarized in a "tornado diagram" as illustrated in Figure E-1.

Figure E-1: Results of Uncertainty Analysis for the Achievable Potential Scenario in 2019



As expected, Figure E-1 shows that dynamic pricing assumptions contribute the most heavily to uncertainty in potential demand response impacts under the Achievable Participation scenario. With low participation in dynamic pricing, the Achievable Participation potential of 138 GW would be reduced by 53 GW to 85 GW, representing a reduction of 39 percent. Higher participation could increase the impacts by 26 GW. The assumed customer response to dynamic pricing also contributes significantly to the overall uncertainty. If customers were found to be more or less responsive to dynamic rates than was assumed in this analysis, total demand response potential could increase or decrease significantly. At the low end, direct load control and Other DR programs do not contribute as significantly to the overall uncertainty.

To put the results of the uncertainty analysis in context it is helpful to know the share of total Achievable Participation potential that is held by each demand response program type. This is illustrated in Figure E-2. It is generally the case that those programs with a larger share of the potential also contribute a large share of the uncertainty.

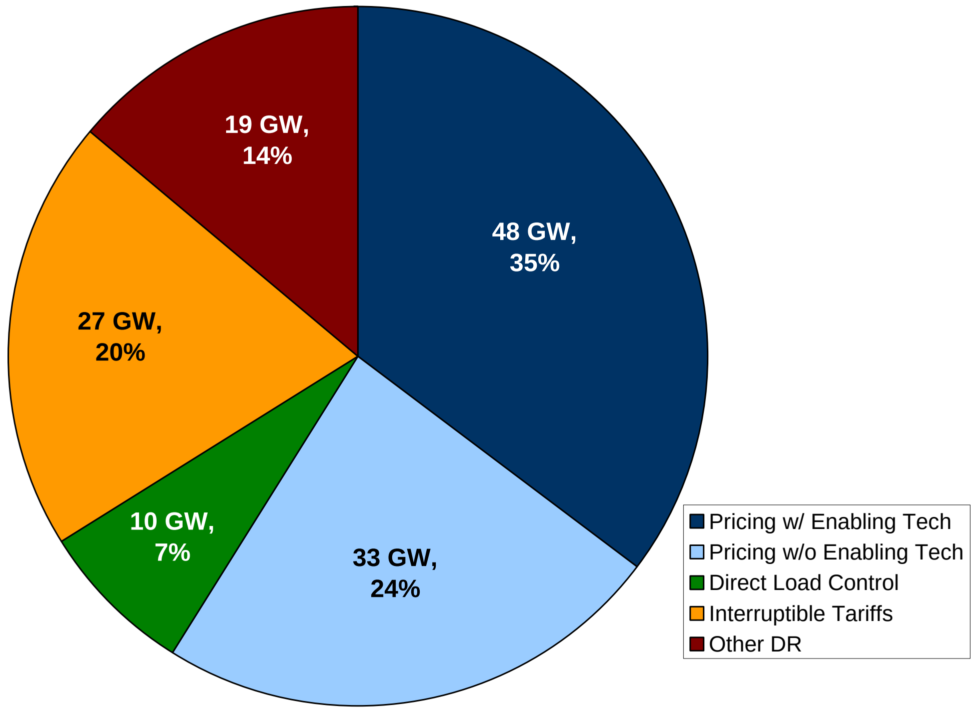


Figure E-2: Share of Achievable Participation Potential for Each Demand Response Program Type, 2019

APPENDIX F. ENERGY INDEPENDENCE AND SECURITY ACT OF 2007, SECTION 529

Energy Independence and Security Act of 2007

TITLE V—ENERGY SAVINGS IN GOVERNMENT AND PUBLIC INSTITUTIONS
Subtitle C—Energy Efficiency in Federal Agencies
SEC. 529. ELECTRICITY SECTOR DEMAND RESPONSE.

(a) IN GENERAL.—Title V of the National Energy Conservation Policy Act (42 U.S.C. 8241 et seq.) is amended by adding at the end the following:

"PART 5—PEAK DEMAND REDUCTION

"SEC. 571. NATIONAL ACTION PLAN FOR DEMAND RESPONSE.

"(a) NATIONAL ASSESSMENT AND REPORT.—The Federal Energy Regulatory Commission ('Commission') shall conduct a National Assessment of Demand Response. The Commission shall, within 18 months of the date of enactment of this part, submit a report to Congress that includes each of the following:

"(1) Estimation of nationwide demand response potential in 5 and 10 year horizons, including data on a State-by-State basis, and a methodology for updates of such estimates on an annual basis.

"(2) Estimation of how much of this potential can be achieved within 5 and 10 years after the enactment of this part accompanied by specific policy recommendations that if implemented can achieve the estimated potential. Such recommendations shall include options for funding and/or incentives for the development of demand response resources.

"(3) The Commission shall further note any barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available, and shall provide recommendations for overcoming such barriers.

"(4) The Commission shall seek to take advantage of preexisting research and ongoing work, and shall insure that there is no duplication of effort.

"(b) NATIONAL ACTION PLAN ON DEMAND RESPONSE.—The Commission shall further develop a National Action Plan on Demand Response, soliciting and accepting input and participation from a broad range of industry stakeholders, State regulatory utility commissioners, and non-governmental groups. The Commission shall seek consensus where possible, and decide on optimum solutions to issues that defy consensus. Such Plan shall be completed within 1 year after the completion of the National Assessment of Demand Response, and shall meet each of the following objectives:

"(1) Identification of requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed.

"(2) Design and identification of requirements for implementation of a national communications program that includes broad-based customer education and support.

"(3) Development or identification of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, States, utilities and demand response providers.

"(c) Upon completion, the National Action Plan on Demand Response shall be published, together with any favorable and dissenting comments submitted by participants in its preparation. Six months after publication, the Commission, together with the Secretary of Energy, shall submit to Congress a proposal to implement the Action Plan, including specific proposed assignments of responsibility, proposed budget amounts, and any agreements secured for participation from State and other participants.

"(d) AUTHORIZATION.—There are authorized to be appropriated to the Commission to carry out this section not more than $10,000,000 for each of the fiscal years 2008, 2009, and 2010.".

(b) TABLE OF CONTENTS.—The table of contents for the National Energy Conservation Policy Act (42 U.S.C. 8201 note) is amended by adding after the items relating to part 4 of title V the following:

"PART 5—PEAK DEMAND REDUCTION

"Sec. 571. National Action Plan for Demand Response.".

APPENDIX G. GLOSSARY OF TERMS

- Ancillary Service Programs: Customers bid load curtailments into various ancillary services markets and agree to be on standby if their bid is accepted. They receive a payment if they are called by the ISO/RTO.

- Capacity Programs: Customers offer load curtailments as a replacement to existing generation in the market. They are generally notified during the day when curtailment is needed. Large penalties are often assessed in the event of non-compliance.

- Critical Peak Pricing: Prices vary by time-of-day and are known to the customer for all pricing periods except that the customer does not know when prices in the critical-peak period may be called. These prices are called on a day-ahead or day-of basis.

- Demand Bidding/ Buyback (Day-ahead): Customers bid load curtailments in the day-ahead market in competition with supply-side resources.

- Demand Bidding/ Buyback (Day-of): Customers bid load curtailments in the day-of market in competition with supply-side resources.

- Direct Load Control: In return for a financial incentive, customers agree to have their end-uses such as air conditioners and water heaters to be controlled by the utility via switches or programmable communicating thermostats.

- Demand Response through Load Aggregators: Load aggregators combine the load reductions of smaller participants and submit these reductions to capacity or other emergency or economic demand response programs.

- Emergency Demand Response Program: Emergency demand response programs provide incentive payments to customers for reducing their loads during reliability-triggered events, but curtailment is voluntary.

- Economic Demand Response Program: Economic demand response programs provide incentive payments to customers for reducing their loads during economic-triggered events, but curtailment is voluntary.

- Emergency Generation: When system's reliability is threatened, system operator may automatically dispatch the generation source at customer's site.

- Interruptible General Service: Customers pay a lower rate in return for agreeing to interrupt their processes to a pre-specified level. This program requires the specification of a baseline or normal usage.

- Load curtailment (a nominated load or a contracted firm demand): Customers are paid a specified amount per MWh curtailed in response to a call that is made on a day-of basis. This requires the specification of a baseline or normal usage.

- Peak Time Rebate: Customers receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours instead of paying higher rates during the critical event hours.

- Peak Shed Programs: Peak shed programs are generally implemented through automating technologies to reduce the load from certain end-use devices and reduce demand charges that will be paid by the customer.

- Peak Shaving via Owned Generation: This is similar to the interruptible/curtailable rate programs except that when the load is curtailed or interrupted, it is replaced by the power from own generation resources.

- Peak Day Credit: program provides qualifying customers with bill credits on all on-peak charges in exchange for an average load reduction of a pre-determined level in consumption across all critical event days within a billing cycle.

- Prepay Programs: Customers prepay for their electricity and have in-home displays that provide information on consumption. While not a demand response program per se, it's observed that prepay programs increase the effectiveness of time-varying rates.

- Real Time Pricing (Day-ahead): Prices may vary on an hourly and sometime on a semi-hourly basis. Customers are provided the prices on a day-ahead basis.

- Real Time Pricing (Day-of): Prices may vary on an hourly and sometime on a semi-hourly basis. Customers are provided the prices on an hour-ahead basis.

- Thermal Storage Program: In this program, customers have electric thermal storage units installed on electric heaters which operate during off peak hours and agree to curtail electric heat during on peak winter periods.

- Time-of-Use Pricing: Prices vary by time-of-day and are known to the customers.

- Utility Controlled Interruptible Rates: Customers pay lower rates in return for agreeing to their service being interrupted by the utility.